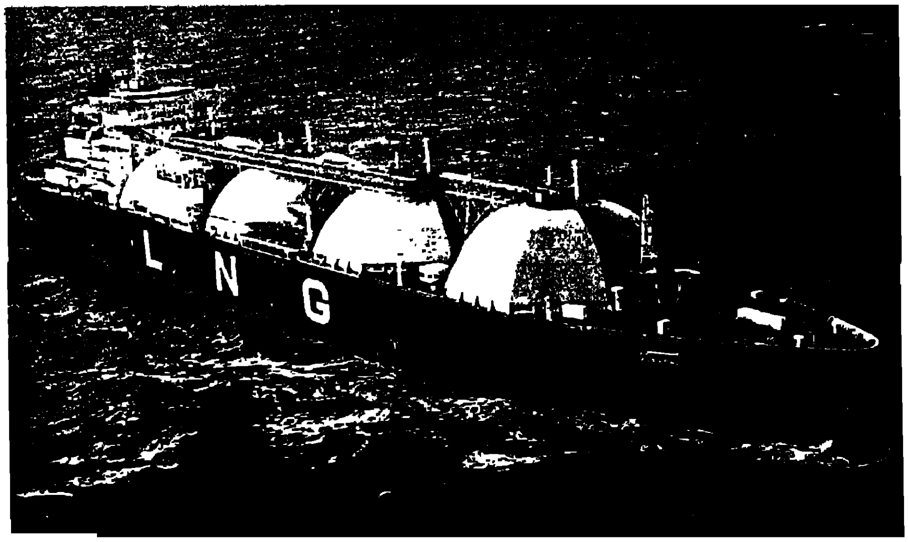
Emergence of a New Giant

INDIA'S NATURAL GAS SECTOR TO 2015



A TERI / FACTS Study

Emergence of a New Giant

INDIA'S NATURAL GAS SECTOR TO 2015

A Multi-Client Study
prepared by

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New Delhi, India

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Abbreviations & symbols

AEC	Ahmedabad Electricity Company Ltd.
ALNG	Australia LNG Ltd.
AMIG	Al Manhal International Group
APEX	Accelerated program of exploration
APIIC	Andhra Pradesh Industrial Infrastructure Corporation Ltd.
APM	Administered Pricing Mechanism
ATF	Aviation Turbine Fuel
BCM	Billion cubic metre
BICP	Bureau of Industrial Costs and Prices
BOO	Build-own-operate
BOOT	Build-own-operate-transfer
BP	British Petroleum Ltd.
BPCL	Bharat Petroleum Corporation Ltd.
Bpkm	Billion kilometres
BRPL	Bongaingaon Refineries & Petrochemicals Ltd.
Btkm	Billion-tonne kilometres
CBM	Coal Bed Methane
CCGT	Combined cycle gas turbine
CEA	Central Electricity Authority
CERC	Central Electricity Regulatory Commission
CFCL	Chambal Fertilisers & Chemicals Ltd.
CIL	Coal India Ltd.
CIS	Commonwealth of Independent States
CNG	Compressed Natural Gas
CPCB	Central Pollution Control Board
CPCL	Chennai Petroleum Corporation Ltd.
DGH	Directorate General of Hydrocarbons
DPC	Dabhol Power Corporation Ltd.
DPR	Detailed Project Report
DVB	Delhi Vidyut Board
E&P	Exploration and production
ECAs	Export credit agencies
EEM	Enron Energy Marketing Company
EEZ	Extended economic zone
EIA	Environmental Impact Assessment

EMP	Environment Management Plan
EPS	Electric Power Survey
ERC	Expenditure Reforms Commission
ESP	Electrostatic precipitator
FACT	Fertilizer and Chemicals Travancore Ltd.
FAI	Fertilizer Association of India
FCI	Food Corporation of India
FDCR	Feedstock Differential Cost Reimbursement
FO	Fuel oil
FOB	Free on Board
GAIL	Gas Authority of India Ltd.
GCV	Gross calorific value
GDP	Gross Domestic Product
GEB	Gujarat Electricity Board
GGCL	Gujarat Gas Company Ltd.
GHCL	Greenfield Holding Company Ltd.
GIDG	GDP Indexed Demand Growth
GIPCL	Gujarat Industries Power Corporation Ltd.
GLL	Gopalpur LNG Ltd.
GMB	Gujarat Maritime Board
GOI	Government of India
GPEL	Gujarat PowerGen Energy Corporation Ltd.
GPLNG	Gujarat Pipavav LNG Limited
GPPL	Gujarat Pipavav Port Ltd.
GREP	Gujarat Rehabilitation and Expansion Project
GSEG	Gujarat State Energy General
GSFC	Gujarat State Fertilisers & Chemicals Ltd.
GSPL	Gujarat State Petronet Ltd.
GTEC	Gujarat Torrent Electric Corporation
HBJ	Hazira-Bijaipur-Jagdishpur gas pipeline
HLPL	Hazira LNG Private Ltd.
HPCL	Hindustan Petroleum Corporation Ltd.
HPPL	Hazira Port Private Ltd.
HSD	High Speed Diesel
IDC	Interest during the construction period
IFC	International Finance Corporation
IFFCO	Indian Farmers Fertilisers Co-operative
IGCC	Integrated Gasification Combined Cycle

IGFCC	Indo Gulf Fertilisers & Chemicals Corp.
IGL	Indraprastha Gas Ltd.
IHI	Ishikawajima-Harima Heavy Industries Ltd.
IOC	Indian Oil Corporation Ltd.
IPPs	Independent power producers
KEL	Kribhco Energy Ltd.
KG	Krishna-Godavari
KIOCL	Kakinada Indian Oil LNG consortium Ltd.
KRIBHCO	Krishak Bharti Co-operative
KRL	Kochi Refineries Ltd.
KSIDC	Kerala State Industrial Development Corporation Ltd.
KSIIDC	Karnataka State Industrial & Infrastructural Development Corporation
KWh	Kilowatt hour
LNG	Liquefied natural gas
LPG	Liquefied Petroleum Gas
LRMC	Long run marginal cost
LSHS	Low Sulphur Heavy Stock
MGL	Mahanagar Gas Ltd.
MMBtu	Million British Thermal Unit
MMCM	Million cubic metres
MMSCMD	Million standard cubic metres per day
MMT	Million metric tonnes
MMTPA	Million metric tonnes per annum
MNCs	Multinational Corporations
MNES	Ministry of Non-Conventional Energy Sources
MoEF	Ministry of Environment & Forests
MoP&NG	Ministry of Petroleum & Natural Gas
MoU	Memorandum of Understanding
MPCE	Monthly per capita expenditure
MS	Motor Spirit
MSEB	Maharashtra State Electricity Board
Mtoe	Million tonnes oil equivalent
MW	Mega watt
NCDC	National Coal Development Corporation
NELP	New exploration and licensing policy
NERA	National Economic Research Associates
NFL	National Fertilisers Ltd.
NGO	Non-governmental organisation

NHPC	National Hydro Power Corporation
NIOC	National Iranian Oil Company Ltd.
NOCs	National oil companies
NRL	Numaligarh Refineries Ltd.
NSSO	National Sample Survey Organisation
NTPC	National Thermal Power Corporation Ltd.
O&M	Operation & maintenance
OCC	Oil Coordination Committee
OCF	Oswal Chemicals & Fertilisers Ltd.
OIL	Oil India Ltd.
ONGC	Oil and Natural Gas Corporation Ltd.
OOC	Oman Oil Company
OPEC	Organization of Petroleum Exporting Countries
OVL	ONGC Videsh Ltd.
PFBC	Pressurised fluidised bed combustion
PFC	Power Finance Corporation
PGCIL	Power Grid Corporation of India Ltd.
PIL	Public interest litigation
PLF	Plant load factor
PLL	Petronet LNG Ltd.
PPA	Power purchase agreement
PS	Pulverised coal subcritical power plant
PSCs	Production sharing contracts
PSM	Payment security mechanism
PTC	Power Trading Corporation Ltd.
R/P	Reserves to production
RCF	Rashtriya Chemicals and Fertilisers Ltd.
RET	Renewable energy technologies
RPS	Retention pricing system
SCCL	Singareni Coal Company
SEB	State Electricity Board
SERC	State Electricity Regulatory Authority
SIL	Seaking Infrastructure Ltd.
SKO	Superior Kerosene Oil
SPCB	State Pollution Control Board
SPM	Suspended particulate matter
SPV	Solar photovoltaic
T&D	Transmission & distribution

TCF	Trillion cubic feet
TCL	Tata Chemicals Ltd.
TEC	Tata Electric Company Ltd.
TGPI	Total Gas and Power India Ltd.
TNEB	Tamil Nadu Electricity Board
TPA	Tonnes per annum
TPC	Tata Power Company Ltd.
TPD	Tonnes per day
TTZ	Taj Trapezium Zone
ULSD	Ultra Low Sulphur Diesel
UPSIDC	UP State Industrial Development Corporation Ltd.
WTO	World Trade Organization

FOREWORD

The world oil and gas industry is impacted not just by market size but also by the incremental growth. It is the change which makes markets and affects global trade. India, along with China, are the two giants which exhibit the biggest incremental growth in the oil and gas markets east of Suez. In the oil business, both China and India have a tremendous impact on the markets. In the gas business, India's role is much more important, in that most of its projected gas demand needs to be satisfied from the outside, while China will rely heavily on her west-east internal pipeline. India's gas needs require both economic and geopolitical solutions. Indeed, India alone is able to affect the flow of gas in many directions, from the Middle East, from Central Asia, from Bangladesh and from Australia. Never before has any gas importer been in a position to impact a regional gas market as well the whole LNG industry so dramatically. India is the new gas giant in the global sense. Understanding the Indian gas market is critical to benefiting from the emerging opportunities which lie ahead as well as avoiding the pitfalls which can be very costly.

Given the emerging critical role of India, the Tata Energy Research Institute (TERI) of New Delhi and Fesharaki Associates Consulting and Technical Services (FACTS) of Honolulu, decided to jointly offer this study to provide the first detailed and objective roadmap to the gas business in India. The study contain demand scenarios developed by TERI, projections of the Hydrocarbon Vision 2025 group and the India Gas Master Plan. The study is essential reading for anyone who in interested in the India gas market as a gas supplier, end user, construction/engineering company, financial institution or geopolitical policymaker.

I would like to gratefully acknowledge the contribution of the team from TERI consisting of Mr R K Batra, Mr D D Arora, Mr A Sen, Mr R D Singh, Ms S Chaudhury and Ms S Malik, who are mainly responsible for this excellent study. I also acknowledge the contribution of Mr. Robert Smith who coordinated the efforts on behalf of FACTS.

Fereidun Fesharaki
President FACTS Inc.

1 Executive summary

Each of the chapters that follow have been summarised highlighting the major policy issues, development and current status of the gas industry, future projections, opportunities available and areas of concern.

Chapter 2 The energy scenario

Introduction

While India is currently the sixth largest energy consumer in the world, per capita energy consumption is the lowest in the top ten energy consumers. Energy demand is, thus, expected to increase considerably over the years to come. The rural sector accounts for about 75% of the total population. It is estimated that 94% of the rural energy use is from traditional bio-fuels like firewood and dung cakes. Energy consumption patterns are expected to change substantially with economic development. Reliance on traditional fuels would reduce with the ongoing rural-urban migrations and the transition to higher income categories within the rural areas.

Oil and gas

The Ministry of Petroleum & Natural Gas (MoP&NG) oversees the entire chain of the oil and gas industry: exploration & production of crude oil and natural gas; refining; distribution & marketing of petroleum products and natural gas, etc.

Exploration and production (E&P) in the country is primarily undertaken by Oil and Natural Gas Corporation Ltd (ONGC) and Oil India Ltd (OIL). The Indian Government has been inviting private participation in E&P since 1993 through exploration rounds, and presently private parties and joint ventures account for about 10% of the total oil and gas production. In order to boost domestic oil and gas production, the government also announced the New Exploration and Licensing Policy (NELP) in 1999.

The installed refining capacity of the country's 17 refineries is 112 MMTPA. A third of the country's refining capacity is in the private/joint venture sector.

Marketing of petroleum products are categorised in two groups: controlled petroleum products - Liquefied Petroleum Gas (LPG), Motor Spirit (MS), Superior Kerosene Oil (SKO) and High Speed Diesel (HSD); and decontrolled petroleum products. While there are no restrictions on sales of decontrolled petroleum products, the prices of controlled products are administered by the Government. In addition, transportation fuels, MS and HSD, can be marketed by the public sector companies only.

The Indian petroleum sector is expected to be deregulated by 1st April 2002. Post-deregulation, any company would be free to market transportation fuels subject to investments of Rs 20 billion ($ 434 million) in refining/other industry infrastructure or annual crude oil production of 3 MMT.

Natural gas is marketed primarily by the Gas Authority of India Ltd (GAIL). GAIL is the largest organisation in India handling post-exploration activities relating to transmission, processing, distribution and marketing of natural gas and its fractions and by-products. GAIL procures natural gas from ONGC, OIL and joint venture consortia in Southern India and the Western Offshore region. GAIL owns and operates the country's only trunk pipeline system - the 2300 km long Hazira-Bijaipur-Jagdishpur (HBJ) pipeline, transmitting 33.4 MMSCMD of gas from the west coast of India to the central and northern parts of country.

Gas is also being marketed by smaller regional companies – by Mahanagar Gas Ltd (MGL), a joint venture between GAIL and British Gas in Mumbai, Maharashtra; by Gujarat Gas Company in the cities of Surat, Bharuch and Ankleshwar in Gujarat; by the Baroda Municipal Corporation in the city of Baroda, Gujarat; and by Indraprastha Gas Limited (IGL), a joint venture between GAIL, BPCL & Government of National Capital Territory of Delhi in Delhi.

India's balance recoverable reserves of natural gas stand at 628 BCM. With gas production in 1999/00 at 28 BCM, the reserves to production (R/P) ratio is only 22 years. The three main producing basins in the country, the Western offshore region, the Cambay basin in Gujarat, and Upper Assam region, are in the mature phase of exploration. The Western offshore region accounts for about 60% of the total gas production in the country. Though private/JV companies started gas production only in 1995/96, their current share in the total gas production exceeds 10%.

Gas sales grew at an average annual rate of 7.1% over the last decade. The bulk of the sales were to power generation and as feedstock in fertiliser production.

The Sub-Group on Development and Utilisation of Natural Gas, constituted under Group on India Hydrocarbon Vision 2025 has projected domestic gas availability to decline from 78 MMCMD currently, to 36 MMSCMD by 2020, in the baseline scenario.

Given the uncertainty associated with exploration and production projects, gas imports are inevitable. A number of proposals for gas imports, via pipelines and as Liquefied Natural Gas (LNG) are under consideration. While there are uncertainties associated with pipeline imports, a number of LNG projects is at various stages of implementation.

With expectations that gas imports, primarily LNG, would materialise by 2005, a number of companies has announced plans for gas based additional capacity (new/expansions), both in power generation and fertiliser production.

Coal

The Geological Survey of India has estimated India's proven coal reserves at 82 billion tonnes. Total coal reserves are estimated at 212 billion tonnes of which nearly 86% are non-coking coal reserves. India is the third largest producer of coal in the world. Coal India Ltd (CIL) and its subsidiaries account for about 85% of the coal produced in India.

Coal reserves are primarily concentrated in the eastern region of the country. Indian coal is generally of low quality with high ash content and low calorific value. The quality of power grade coal has been deteriorating over the years. Since adequate quantity of the requisite quality of coal are not available, coal imports have increased lately.

Coal production (non-coking), has more or less stagnated over the last three years, with an annual growth rate of less than 2%. The output per manshift is Indian mines is significantly lower than international standards. Investments in new mining projects has been poor over the last few years. The share of output from opencast mines, which contributed only about 28% of the total production at the time of nationalisation of mines in 1973, is now more than 70%. Over reliance on opencast mining has led to rapid depletion in coal reserves. Exploitation of shallow seams in the past now requires mining of deeper seams, which would eventually lead to high long run costs of coal production.

Given the important position of coal and lignite resources in India's overall energy strategy and the urgent need for development of these resources, the Planning Commission constituted a Committee on "Integrated Coal Policy", which submitted its report in May 1996. However, deregulation of the prices and distribution of all grades coal and coal products are the only recommendations implemented so far by the Government. Considering all factors, coal production in India is likely to plateau at around 600 MMTPA by 2025.

Electricity

The country's installed capacity as on 31st March 2000 aggregated 97,837 MW. During 1999/00, against energy requirements of 480 TWh and a peak demand of 72, 669 MW, the available energy was 451 TWh and the peak demand met was 63,691 MW. The associated energy deficit was 6.2% and the peak deficit 12.4%.

The IX Plan envisaged a total capacity addition of 40 245 MW. Actual capacity addition of 12,000 MW during the first three years of the Plan (1997/98 - 1999/00), however, has been below targets. The mid-term review of the IX Plan, scaled down the capacity addition target to 28 097 MW.

The transmission & distribution (T&D) system is a serious cause for concern. While T&D losses in 1999/00 were reported at 22%, the actual losses are significantly higher as these include power thefts.

Electricity sales have increased at a healthy 6.4% over the last decade. Sales to the agriculture and industry sectors account for about 30% each of the total sales, while domestic consumers account for about a fifth. The 16th Electric Power Survey of the Central Electricity Authority (CEA), projects energy requirements to grow at an annual rate of 6.3% over the period 2001-2017.

There are severe tariff distortions in the power sector. While the agriculture sector accounts for nearly a third of the total electricity sales, the revenues from this sector contribute to only 3.6% of the total realisation due to subsidised tariffs. Subsidies are also extended to domestic consumers, which together with the agriculture sector account for about half of the power sales, but only a sixth of the realisation. On the other hand, the industry and commercial sector account for 80% of the realisation from only a third of the sales. The State Electricity Boards (SEB) are in a poor state of financial health with cost recoveries of the order of 74% only. In 1999/00, while the average cost of generation was Rs 2.8/kWh, the average realisation was only Rs 2.1/kWh. Commercial losses of SEBs in 1998/99 aggregated Rs 134 billion ($ 2910 million).

Recognising the critical role of the power industry in the country's infrastructure, the Government initiated a series of reforms in 1991 targeted at improving the performance of the industry, corrections of tariff distortions, encouraging participation of the private sector, etc. In 1998, the Government passed a legislation enabling the establishment of independent and autonomous regulatory bodies at the centre and state level. The Central Electricity Regulatory Commission (CERC) was to regulate tariffs of central generating companies and other generating companies. State Electricity Regulatory Authorities (SERC) were empowered to determine tariffs payable for intrastate transmission and supply of electricity. SERCs were also expected to regulate the working of licensees and others involved in the electricity industry in the state. By March 2000, 13 states had set up SERCs.

India's future energy scenario

Current self sufficiency in oil is only about 30%. Even if domestic crude production is raised to 100 MMT by 2025, crude imports are likely to be of the order of 254 MMT, i.e., about a third of the entire current crude imports into the Asia Pacific region. Domestic gas production is expected to reduce to less than half the current production levels by 2020. Despite large reserves, production of coal is likely to finally plateau at about 600 MMTPA making large scale coal imports inevitable. With coal resources concentrated in the eastern region of the country, all-India distribution would emerge as a critical problem due to bottlenecks in the transportation system. The choice between imports of coal and gas would be governed by inter-fuel economics and availability. Other governing factors would be transportation logistics, port handling capacity etc. Energy security concerns would require diversification of fuels and supply sources. Growing environmental concerns would drive the switch to cleaner fuels. The thrust towards adoption of renewable energy technologies (RET) has gained considerable momentum in India. A National Renewable Energy Policy under consideration envisages that 10% of the installed generating capacity should be based on renewables by 2012.

Chapter 3 Energy and fertiliser sectors policies

Natural gas

Opening up exploration and production

Of the 3.14 million square km sedimentary basins 67% is unexplored. Of the balance, about half is moderately explored, and the other half is poorly explored. The exploratory drilling intensity is low compared to that of USA. The Eighth Five-year Plan period (1992–97) started on a poor note. The accretion in the first three years was far short of target and the government decided to launch an accelerated program for exploration (APEX), which had a number of components including:

- A national seismic grid
- Exploration in frontier areas and deep waters.

In spite of this mid-course correction, reserve accretion targets were not met by the end of the plan period which resulted in bringing in the private sector. Exploration bidding rounds started in 1979, far ahead of the economic reforms of the 1990s. The result of this effort has been that 35 exploration blocks and 30 discovered fields have been awarded to the private sector. The total investment brought into the sector so far, mostly in producing fields, exceeds $1 billion. Production of crude oil and natural gas from these fields has increased over the years to about 10% of the total production.

There is general agreement that these have not met expectations and a number of reasons are cited for the disappointing results. There was a perception that the blocks with better prospects were reserved for the NOCs and only the high-risk areas were offered to the private investors. The seismic data provided was inadequate in most cases in addition to being old and expensive. The NOCs continued to hold on to the blocks they were awarded on a nomination basis. They also played a decisive role in the delineation of the blocks to be offered in the bidding rounds.The other factor, a very important one, was the delays in policy making and implementation of the exploration sector policies.

With a view to removing these shortcomings, a New Exploration Licensing Policy was formulated by the government in 1997-98 to provide a level playing field in which all parties could compete on equal terms for the award of exploration acreage. The first bidding round was launched in 1999. The NELP attracted 45 bids for 27 blocks, from which the MoP&NG approved the award of 25 blocks. Exploration blocks under the Second Round of NELP were offered in December 2000. Altogether, 25 blocks were put on offer in NELP II, including 8 deepwater blocks. By 31st March 2001, the closing date for NELP II, 13 companies submitted bids for 23 blocks - 8 deepwater, 8 shallow water and 7 onland. The exploration under the first NELP round has already started producing results. Cairns have found gas in three structures in Cambay offshore and is expecting a much bigger find in the offshore KG basin.

The government is reportedly considering the introduction of continuous bidding as the logical next step but no announcements have been made as to when this would be introduced.

Promoting the import of LNG

In 1996 the government decided to encourage the import of LNG and formed Petronet LNG by bringing together the public sector giants - IOC, ONGC, GAIL and BPCL. No restrictions were put on private imports and within a short time a large number of projects were proposed and approved.

LNG contracts typically last 15-20 years and may put pressure on foreign exchange reserves if exports do not do well. Secondly, gas is used mostly for power generation and production of urea. Both the commodities are heavily subsidised by the government – power by the state governments and urea by the central government. Any increase in LNG use or the LNG price therefore increases the subsidy burden. Indications are that the government will make serious attempts to contain and reduce the subsidy burden.

Regulation of the LNG industry

The government has considered the need to regulate the location and size of the LNG terminals, put a cap on the number of proposals to be approved in a particular region and oversee the feasibility of the proposals. While a policy statement on LNG has been expected for some time it is likely that the government would leave these matters to the market to decide.

The union budget of February 2001 has rationalised the import duty structure for LNG removing the disparities that were earlier there between the power and other importing sectors. However, the eagerly awaited announcement granting 'infrastructure industry' status to the LNG industry did not come through.

One important factor that would influence the choice between LNG and the alternatives of naphtha and fuel oil is the customs duty. Indications are that the country would have an excess of both naphtha and fuel oil in future and the government may well protect the domestic industry with high import duties. LNG could therefore continue to have a lower duty than fuel oil/naphtha.

LNG shipping policy

The policy is yet to be officially announced but the broad parameters are known. LNG transporters are to have at least 26% equity held by an Indian shipping company throughout the period of the contract. Further, the Indian company has to be associated in operating the ships so that there is effective transfer of know how in manning and operation of these vessels by Indian personnel. The Indian partners in the shipping consortium should together hold 50% equity. The policy allows only fob imports of LNG at present. This would be reviewed after seven years.

Regulatory framework

In order to examine the options for a regulatory framework for the gas industry, the government commissioned a study by the NERA. A summary of the recommendations is given below.

- Exclusivity to develop new transmission lines, and extensions and additions to new lines, should not be granted to GAIL or any other entity,
- Gas transportation should be provided on the basis of "unbundled" service,
- Transmission services be provided on the basis of contract carriage,

- Distribution systems should be regarded as separately regulated entities, and subject to distinct regulatory provisions.

Gas Act

The government has so far controlled gas production and marketing by virtue of being the owner of ONGC and GAIL. Ever since the submission of the NERA report, there has been an expectation of a Gas Act installing an independent regulator. It seems however that the government is not yet prepared to have an independent regulator in place and that regulation by government would continue for sometime. While the central government dithered, unable to decide on the merits of a Gas Act, Gujarat, where 4 LNG import terminals are planned, has gone ahead and enacted its own gas law.

Pipeline tariffs and third party access

The transportation charges along the HBJ pipeline is decided by the government. It was first fixed in 1987 and subsequently revised in 1997. GAIL was allowed a 12% post-tax return on equity. Consumers along the 2300 km long HBJ pipeline are charged the same tariff irrespective of location. This 'postage stamp' tariff is likely to continue; a distance related tariff and the need to feed in LNG would make the tail-enders non-viable. However, with the entry of private operators in gas production and transportation, a distance related tariff is likely to emerge for new pipelines.

An important consideration for the LNG importer is whether access would be available into the existing pipeline network of GAIL. Unfortunately, there is no clarity on this issue. LNG importers would have to negotiate the terms of access with GAIL. Wherever feasible, they may try to rope in GAIL as a partner in the LNG project.

Gas allocations to consumers

Gas prices have been fixed by the government since 1987. The government also makes gas allocations to individual consumers. The regime of allocation was based on the premise that gas was in short supply and that the government was the best judge of how to use the gas. The first departure from this system of allocation was made in the cases of private producers of gas under production sharing contracts. These developers were free to choose their customers and sell gas to them at negotiated prices. These developments point towards the abolition of the allocation regime and its replacement by market forces.

Pricing of gas

The price of natural gas has been fixed by the Central Government since 1987. The Kelkar Committee appointed in 1990 recommended that the price payable to the producers be fixed at the long run marginal cost of production. In 1996 the Sankar Committee decided that import parity pricing would be too steep a transition. The committee left intact the principles of fixing the producer price and the consumer price earlier recommended by Kelkar. The prices were however revised upward based on fresh estimation of the costs.

Having considered these recommendations, in October 1997 the government instituted a new series of gas prices, valid through to March 31, 2000. The consumer price of gas at landfall points were linked to the price of a basket of fuel oils. The gas price, although it continued to be an administered price, was brought close to market prices. A major device introduced to protect the producers as well as the consumers was a floor price of $1.32/MMBtu and a ceiling price of $1.76/MMBtu. The price has now reached the ceiling and is being reviewed with a view to introducing 100% fuel oil parity prices. The transportation charges on the HBJ pipeline were revised in 1997 to $0.71/MMbtu. In addition royalty, taxes, duties and other statutory levies is payable by the consumer. There is no excise duty on natural gas. A sales tax is leviable at state rates if the sale is within the state or at the central rate of 4% for inter-state sales. In addition there would be a customs duty to be paid on imported gas/LNG. This duty is now 5%.

With the present high prices of fuel oil, the gas price which is now capped at $1.76/MMbtu would jump to around $3.6/MMbtu. The price along the HBJ would then be $4.28/MMbtu. The consumers are resisting this steep increase. The steel industry, an important gas consumer now reeling under recession will be hit badly. The Finance Ministry is unhappy because the fertiliser subsidy will go up sharply.

Petroleum

At the time of independence, the petroleum industry in India was run by multinational companies, Burmah Shell, ESSO and Caltex. The ONGC and the Indian Oil Corporation were formed in the late fifties. In the seventies, the assets of the MNCs were acquired by government on a negotiated sale basis. By the time the economic reforms were launched in the nineties, the industry was dominated by public sector companies engaged in exploration, refining, marketing and distribution.

The upstream sector was the first to be opened up to the private sector. Next, the private sector was allowed into refining. This has proved to be the most successful initiative so far resulting in 27 MMTPA of additional capacity put up by Reliance at Jamnagar with other proposals in the pipeline.

Opening up of the lucrative marketing sector has been scheduled for April 2002. The existing regulations were built around the Administered Pricing Mechanism (APM) introduced in 1976.

This mechanism has served the following objectives:

- To ensure availability of certain products at subsidized rates to the economically weaker sections of the society and for priority sectors like fertilizers. This is achieved through a system of cross subsidization of products,
- To ensure stable prices so that the domestic market is insulated from the volatility of prices in the international market,
- To regulate returns to the oil companies at reasonable levels consistent with efficiency of operations.

In spite of these features, the system proved unworkable for several reasons. The government accordingly announced a phased reform program starting April 1, 1998. The important features of the program were:

- Fixed time frame for implementation (1998-2002),
- International price for domestic crude oil,
- Retention pricing for refineries abolished,
- Market pricing for products.

At present it looks as though a single regulator would be installed for the gas and the downstream petroleum sectors while another regulates the upstream sector. The appointment of independent regulators would be preceded by an interim arrangement where a departmental official may be appointed the regulator.

Coal

The coal industry in India was largely in the hands of the private sector until the end of 1971 when the coal industry was nationalised. Coking coal mines were taken over in October 1971 and other coal mines in January 1973. Subsequently, the industry was reorganised with Coal India as the holding company and seven coal producing subsidiaries, operating mines in different regions. A massive investment of about Rs. 180 billion ($ 3900 million) has been made in opening up of new mines, re-organisation of existing mines and development of associated infrastructure. Coal production has registered an annual growth rate of about 4.8 % since nationalisation, increasing from a level of 73 MMT in 1970/71 to 300 MMT in 1999/2000.

Till the end of the Seventh Five-year Plan (1990) the coal sector depended fully on the budgetary support provided by the government for new developments including exploration. From the Eighth Plan onwards, the government has phased out this support. Due to this reason, investments in new projects has been low in the last few years. This is likely to increase the gap between production and demand in the future.

In 1996, the government deregulated the prices of A, B & C grades of non-coking coal and all grades of coking coal. In February 1997, the government decided to deregulate the prices of 'D' grade non-coking coal, hard coke and soft coke. Finally, the prices of E, F & G grades of coal were decontrolled on 1st January 2000.

Since the capacity in eastern sector is larger than the demand, coal moves over long distances to the north and west. The freight rate is more than 50% of the delivered cost of coal at 1000 km.

The government protects the domestic coal industry with a customs duty. In the case of non-coking coal, the present rate of custom duty is 25 % with a surcharge depending on the ash content. The import of coal is however increasing and around 7.5 million tonnes of non-coking coal were imported in 2000.

In a major policy initiative, captive coal mining has been allowed to both private sector and public sector companies including the state power utilities for generation of power, production of iron and steel, cement and for washing of coal. Foreign investment in Indian companies taking up coal mining activity for captive consumption for approved end-uses has been allowed. The extent of equity participation is decided on a case to case basis. Captive mining is yet to really take off. Lack of facilities such as power and railway lines near the allotted blocks as well as the difficulties in the power sector have been the important factors.

To facilitate coal sector reforms it may be necessary to appoint an independent regulatory body for this sector. The government has recently completed studies in this regard. The report is under consideration in the government.

Electricity

Like the petroleum industry, the power sector has been characterised by cross-subsidies. In the oil industry these cross-subsidies are between products; in the power sector these are between different kinds of consumers. Supplies to the agricultural and residential sectors are subsidised by overcharging industrial consumers. As the limits of cross-subsidy were reached, net subsidies from the government were required. These were mostly inadequate and often delayed. The result was that the electricity boards in the states suffered losses and were in no position to make the investments necessary to meet the rising demand for power.

Projections made at the time of formulating the ninth five year plan pointed to the need to add 10,000 MW every year. There was a clear need to rope in the private sector in power generation, transmission and distribution and the institutional set up had to be changed to make this possible.

The Electricity Regulatory Commission Act, 1998 came into force in July 1998. This Act provides for the establishment of the Central Electricity Regulatory Commission to regulate the tariff of the generating companies owned by the central government, to regulate the tariff of other generating companies selling electricity to two or more states and to regulate inter-state transmission of electricity. The Act also provides for the establishment of state level regulatory commissions. Several states have set up Regulatory Commissions. Some have gone further and split up the electricity boards.

The Transmission Bill facilitating the entry of private sector in the transmission business was passed by the Parliament in 1998. The bill is aimed only at facilitating private investment. The Government will continue to retain control over power transmission through central grids or SEBs. The bill will allow private firms to invest in facilities for transmission and to operate and maintain these facilities.

In view of the slippage in setting up additional generation capacity in the Ninth Plan, the government has announced a policy package for mega power projects to be developed in the country. To qualify for incentives under this scheme, a project has to satisfy the following three conditions:

- The capacity should be more than 1000 MW in case of thermal power projects and 500 MW in case of hydroelectric power projects,
- The project should sell power to more than one state,
- The tariff should be approved for Central Electricity Regulatory Commission.

The incentives include a complete waiver of the customs duty on import of equipment, which is currently more than 20 percent. It also provides a 15% price preference and deemed export benefit for domestic bidders.

The pace of changes in the sector has been slow. This is understandable in view of the dimension of the problem being addressed. It is however true that the regulatory commissions have been able to put the reforms agenda firmly on the table. The success of the reforms would determine the extent to which the electricity boards would, in the long run, be able to support additional generation capacity based on LNG or any other fuel. In the short run, the state governments would have to bail out the utilities.

The case of the Dabhol Power Project of Enron in Maharashtra has drawn much flak recently. When a project suffers such a setback, the future of reforms becomes suspect. It may be remembered, however, that this project belongs to the period immediately following the opening up of the power sector. Since then the selection of IPPs through competitive bidding has been established and much better terms have been negotiated in a number of projects. As is the case in Maharashtra, state regulatory authorities will increasingly insist on merit order despatch. This will require that all new plants ensure that their tariff is such that they are fairly high up on the merit order so as to achieve the planned plant load factor. Competitive bidding along with stable fuel prices would guarantee the success of individual projects as well as that of power sector reforms.

Fertilizers

The production of foodgrains in the country has risen from a level of 52 million tonnes in 1951-52 to 202 million tonnes in 1998-99.

The installed capacity as on 29.2.2000 has reached a level of 11.71 million MT of nitrogen (inclusive of an installed capacity of 20.67 million MT of urea) and 3.65 million MT of phosphate nutrients, making India the third largest fertilizer producer in the world. Today, there are 64 large sized fertilizer plants in the country, manufacturing a wide range of nitrogenous, phosphatic and complex fertilizers. The Government's policy has aimed at achieving the maximum possible degree of self-sufficiency in the production of nitrogenous fertilizers based on utilization of indigenous feedstock. As of now, the country is self-sufficient to the extent of about 92.1% in the case of nitrogen.

In view of the limitations on availability of gas, a number of expansion projects were taken up in the last few years with naphtha as feedstock with the flexibility for switching over to gas when available.

On grounds of food security, the government would like to maximise domestic production capacity. The international urea price has shown sharp increases whenever India and China have increased their imports. Accordingly the government plans to limit imports to around 10% of the requirement. This would mean that another 20 million tonnes of new capacity needs to be set up. This additional capacity can only be gas/ LNG based. These units would be under a strong competitive pressure from imported urea and would have to be protected by a suitable tariff.

Prices of urea are controlled by Government. Fertiliser plants operate under a Retention Pricing Mechanism somewhat similar to the Administrated Pricing Mechanism for the Petroleum Industry.

The government has attempted in the past to decontrol urea prices but has not been able to do so under pressure from cultivators. The Expenditure Reforms Commission (ERC) has now recommended that urea prices be decontrolled by 2006. There is considerable uncertainty as to whether this can be done. There is also some uncertainty on how the WTO obligations would affect the agriculture sector, especially the production of fertiliser intensive foodgrains.

Chapter 4 Inter fuel economics

The power and fertiliser sectors are the anchor customers for gas. The competing fuel for gas in power generation is coal. In the fertiliser sector, gas has to compete with naphtha and imported urea. To assess the competitiveness of gas vis-à-vis other fuels, the imputed values or replacement values of gas in power generation, urea production and industries in general have been estimated. Imputed value of gas is the price of gas at which the cost of generation/production in a gas based plant equals the cost of generation/production using an alternative fuel, at a particular location. Thus it indicates the maximum price for gas to make it competitive with alternative fuels.

Five locations in India have been considered for estimation purposes – Visakhapatnam on the east coast of India, Bangalore in the south, Hazira on the west coast and Bathinda and Bokaro in the north and east respectively.

The power sector

Assumptions

Imported coal

Two scenarios of cif prices of imported coal at Indian ports have been considered: cif at the current marker price of $ 34 /MT and also at $ 45 /MT.

Domestic coal

Here again two prices have been considered: Current power coal prices and the long run marginal economic cost (LRMC) of production as it is assumed that prices of coal will reach the economic costs in the long run.

Technologies

Technologies considered for power generation are:

- combined cycle advanced class gas turbines (CCGT),
- pulverised subcritical (PS) coal-based plant,
- supercritical coal-based plant.

Imputed values

Domestic coal has the lowest imputed value at all locations ($ 3.22/MMBtu at Bokaro to $ 5.50/MMBtu at Bathinda) except at Bangalore where imported coal at the low cif price scenario is at par with domestic coal ($ 6.60/MMBtu and $ 6.42/MMBtu for subcritical and supercritical respectively).

Natural gas can compete against coal if made available at Bokaro and Vishakapatnam at $ 3.2/MMBtu and $ 4.1/MMBtu respectively (ex. Bangladesh?) and at Bhatinda, Hazira and Bangalore in the range of $ 4.8/MMBtu to $ 6.0/MMBtu depending on the location.

The fertiliser industry

The alternative feedstocks to gas in urea production are naphtha and fuel oil. Fertiliser production with fuel oil is practically an outdated technology. For comparison the imputed values of gas have been assessed against naphtha and imported urea.

Assumptions

- Imported parity pricing for naphtha has been assumed. At present there are no customs duty or CVD on imports of naphtha for use in fertiliser industry.
- The landed cost of imported urea at the Indian coast is assumed at $ 150/MT. Currently there are no import duties on urea in India.

Imputed values

Naphtha imputed values range between $5.13/MMBtu and $6.12/MMBtu at low crude oil prices and between $7.23/MMBtu and $8.21/MMBtu at high crude oil prices.

Gas at around $5.00/MMBtu can compete with naphtha at all locations. Imported urea's imputed value ranges between $2.03/MMBtu and $2.67/MMBtu. On imputed value considerations alone, naphtha and natural gas cannot compete with imported urea at any location.

Though the economics of importing urea seem attractive, when India makes large purchases in the international market it pushes up urea prices. India is the second largest urea importer in the world. In 1995-96 India increased urea imports to 21% of total consumption. Consequently, India had to pay as much as $ 250/MT for urea imports. At such high prices, imputed values of gas range between $ 6.70 - 7.34/MMBtu. Then gas becomes very competitive vis-à-vis urea imports. More than marginal dependence on imports also raises questions about food security. Any disruption in urea supply will have significant adverse impacts on agricultural production. Consequently urea imports is expected to account for only about 10% of total urea demand.

General industries

Industries use coal, fuel oil and LPG as an underboiler fuel or for providing heat for process operations. Certain industries i.e. refractories, glass and ceramic manufacturers require clean fuels such as LPG or natural gas for quality control reasons. Imputed values of gas have been computed on a simple calorie equivalence basis for the above three fuels.

Imputed values

Domestic coal, imported coal, fuel oil and LPG have ascending values at Bokaro and Visakapatnam. At Bhatinda, Hazira and Bangalore imported coal at low cif-values scores over domestic coal at LRMC.

Natural gas is uncompetitive against domestic and imported coal at all locations. It can compete against fuel oil at low crude prices if priced at around $ 4.00/MMBtu and is competitive against fuel oil at high crude prices and LPG.

Other factors governing choice of fuels:

- Natural gas, LPG and fuel oil have greater combustion efficiencies than coal. If taken into account their competitiveness vis-à-vis coal will improve significantly. Also glass and ceramic manufacturing require continuous process heating in a controlled manner which makes gas and LPG preferable to coal.
- Imputed values of gas against LPG are very high, averaging around $ 7.3/MMBtu to $ 8/MMBtu at low crude price scenario. Given a choice between gas and LPG in glass and ceramic industry, gas will be preferred over LPG.
- Consumption of domestic coal in industries has declined in most states in India. The monopolistic attitude of CIL is somewhat responsible for this decline. Often the desired quality of coal is not made available by CIL to small industries. In addition delays in coal supply are frequent for these small consumers. Consequently industries are shifting over to imported coal, LPG and natural gas. Compared to coal, gas has some obvious advantages. Steam-fired boilers need adequate time to start up or shut down while gas based plants are more flexible. Also gas has a distinct advantage over coal on environmental grounds.
- Increases in coal production is primarily restricted to the eastern region of the country. It will be difficult to extend the already saturated rail transport capacity for widespread distribution of coal throughout the country.

Chapter 5 Gas demand

Current scenario

Although the gas industry has witnessed a rapid development since, gas usage accounted for only 8% of the total primary energy consumption in the country in 1999. The structure of gas consumption has also changed. Current gas consumption for power generation equals that for fertiliser production, with each sector accounting for about 40% of the total gas consumption (see Table 1.1).

Table 1.1 Sectoral gas consumption in 1999/00: MMSCMD

Region	Fertiliser	Power	Sponge Iron	Others	Total
Western offshore	20.9	14.6	3.1	4.5	43.1
Onshore	3.0	8.3	-	1.9	13.2
Total	**23.9**	**22.9**	**3.1**	**6.4**	**56.4**

Till the late 1980's supply of gas was restricted due to a lack of infrastructure. Gradually, with both supply and demand picking up, the Government had to resort to a system of gas allocations through the inter-ministerial Gas Linkage Committee. Since current gas allocations far exceed availability, expansion projects of existing consumers/new facilities are being planned on imported gas via pipelines and as LNG.

Short term outlook for gas demand

The short term demand is based on gas-based expansion plans of specific power plants and fertilizer plants and difference between allocation and sales for the other sectors.

Since these expansions are linked to gas imports, the time-frame for this demand to materialise coincides with the commencement of LNG imports, i.e., by 2005 (Table 1.2).

Table 1.2 Short-term gas demand outlook (MMSCMD)

Year	Power	Fertiliser	Industry	Transport	Domestic	Total*
1999	25.0	24.4	9.1	0.1	0.7	59.4
2005	55.9	33.2	11.9	0.5	1.3	102.7

* Gas for captive use, LPG shrinkage and other non-energy uses (5.8 MMSCMD in 1999) ignored in forecasts

Long-term outlook for gas demand

Conventional analyses on long-term demand forecasts rely on trend analysis. However, in the case of the Indian gas industry it has not been possible to project demand by a simple trend extrapolation as restricted gas sales do not reflect actual demand. In addition, administered prices for natural gas disassociate "perceived" demand from inter-fuel economics. Three scenarios have been analysed in this chapter, two based on prior studies and one new scenario developed for this study.

- Scenario 1: Development of Natural Gas Masterplan" by the Bechtel Consulting-London Economics-Centre for Energy, Petroleum and Mineral Law Technology-TERI consortium (1998).
- Scenario 2: Sub-group on Development and Utilisation of Natural Gas in "Hydrocarbon Vision 2025" (1999).
- Scenario 3 (new): GDP Indexed Demand Growth (GIDG)

Scenario 1: Natural Gas Masterplan

The projections for the power sector draw on the 15th Electric Power Survey (EPS) of the CEA. These forecasts were used by the CEA to develop the Fourth National Power Plan which detailed the plan wise schedule for additions to power generating capacity.

The study analysed the economics of gas use for power generation for the proposed thermal capacity addition. The imputed value for gas was assessed at 42 representative locations covering the entire country at different price levels, namely, below \$3/MMBtu, between \$3-\$4/MMBtu and above \$4/MMBtu. In case of fertilisers sector, the study considered fertiliser production in India uneconomical and recommended imports.

Gas demand estimates from the study at a price of \$4/MMBtu are summarised in Table 1.3.

Table 1.3 Scenario 1: Gas demand projections under Natural Gas Masterplan (MMSCMD)

Year	Power	Fertiliser	Others	Total
2001	40	38	12	89
2006	73	38	12	122
2011	112	38	12	161

Scenario 2: Hydrocarbon Vision 2025

Gas demand for power generation also employ the results of the Fourth National Power Plan. The study reviewed thermal capacity additions indicated in the Fourth National Power Plan, and assessed gas demand for two scenarios, i.e., gas prices at \$3/MMBtu and at \$4/MMBtu. For projections beyond 2020, the long-term forecasts by NTPC of likely gas based capacity were utilised.

In case of gas use for fertiliser production, the study envisaged maximum urea imports of 2 MMT, with the balance requirements to be met from indigenous sources. Urea demand estimates were based on forecasts made by the Fertiliser Association of India for foodgrain requirements for the country.

Gas demand projections under the second scenario, i.e., at a price of $4/MMBtu are presented in Table 1.4.

Table 1.4 Scenario 2:Gas demand projections under Hydrocarbon Vision (MMSCMD)

Year	Power	Fertiliser	Others	Total
2001	40	54	23	117
2006	67	66	33	166
2011	90	83	43	216
2024	153	105	64	322

Scenario 3: GDP indexed demand growth (GIDG)

Long-term projections of gas demand for the present study have been derived from the likely gas use in different sectors – power generation, fertiliser production, transport and domestic use. These forecasts are based on outlooks for growth in different sectors of the economy. Sectoral economic growth has been adjudged in terms of the growth in value added by a sector. The long-term forecasts in this analysis are based on a 6% growth in the economy over the period 2000-2015.

- Gas use for power generation: Gas demand for power generation stems for demand forecasts for power. These are adjusted for transmission & distribution (T&D) losses to arrive at generation requirements at the bus bar. Next, likely generation from other sources –nuclear, hydro, renewables and imports of power from neighbouring countries is netted out to assess requirements of thermal generation. Gas based thermal generation is then estimated as the residual generation after identifying likely thermal generation from other sources, namely, coal and oil. In the case of coal it is assumed that by 2015 availability of domestic coal will be restricted to 450 MMT and import of coal would have risen to 40 MMT.
- It is assumed that 90% urea demand is met indigenously and that all urea production is gas based by 2010.
- Given the diverse spread in usage, projections for industrial gas demand are based on the aggregate intensity of gas use in the industrial sector, i.e., the amount of gas consumed per unit of value added from the manufacturing sector. The share of energy intensive industries in the value of output from the manufacturing sector has been declining over the past couple of decades. Growth in intensity for the projection period is suitable moderated.

Gas demand projections under the third scenario are presented in Table 1.5

Table 1.5 Scenario 3: Gas demand projections summary (MMSCMD)

Year	Power	Fertiliser	Industry	Transport	Domestic	Total#
1999	25.0	24.4	9.1	0.1	0.7	59.4
2005*	55.9	33.2	11.9	0.5	1.3	102.7
2010	69.3	40.3	15.6	0.7	1.7	127.6
2015	78.8	46.3	21.9	1.0	2.7	150.8
CARG	7.4%	4.1%	5.7%	15.4%	8.9%	6.0%

* Short-term estimates (supply driven)

# Gas for captive use, LPG shrinkage and other non-energy uses (5.8 MMSCMD in 1999) ignored in forecasts

Comparative analysis

There are considerable variations in estimates for gas demand projections under the four scenarios:

Power

Estimates of gas demand for power generation in 2015 varies between 79 MMSCMD to 152 MMSCMD. Gas demand projections under the Scenario 3 GIDG set the lower-bound on the forecasts. Scenario 3 reflects the latest assessment of power demand and also takes into account the import of coal based on its competitiveness with domestic coal in certain regions.

Fertilizer

Scenario 1 Natural Gas Masterplan did not favour indigenous fertiliser production and recommended imports of urea. However, given issues of food security for the country, such a policy does not hold merit.

Fertiliser requirements under Scenario 2 are estimated to increase by an additional 20 MMT by 2017. As India is self-sufficient in foodgrain production at present and fertiliser production in the country has increased by only 11 MMT over the last two decades, an additional requirement of 20 MMT of fertilisers by 2017 seems unlikely. Gas demand in 2015 for fertiliser production is likely to be around 46 MMSCMD as projected in Scenario 3.

Industry

A direct comparison of industrial gas requirements is not possible as Scenario 1 Natural Gas Masterplan offers projections for gas use in sponge iron units only, while Scenario 2 Hydrocarbon Vision 2025 clubs industrial requirements with all non-power and non-fertiliser uses. While an assessment of gas demand as industrial fuel would require a detailed analysis it is expected to be around 22 MMSCMD by 2015 as projected in Scenario 3.

Preferred gas demand scenario

Based on the comparative analysis, Scenario 3 is the preferred scenario for gas demand and has been used in the subsequent chapter to determine the supply/demand balance and import requirements.

Chapter 6 Domestic gas supply and supply-demand projections

Major gasfields

There are three major areas of gas production in India today:

- The Western Offshore region which extends from offshore Mumbai to the Gujarat coast
- Assam
- Gujarat onshore region

There are also gas fields in Rajasthan, Arunachal Pradesh, Tripura, the Cauvery basin and the Krishna-Godavari basin which is considered the most promising.

The current output is heavily concentrated in the western offshore fields accounting for 17.5 BCM of the total 27.4 BCM of gas produced in 1998/99. Onshore Gujarat fields produced 3.1 BCM gas.

The Western Offshore region

This comprises the large Bombay High field and other associated gas fields. This region also has a number of free gas fields the largest of which is South Bassein.

Bombay High

Discovered in 1974, with initial total gas reserves of some 400 BCM, Bombay High field is by far the largest associated gas field in India. Production from the field is expected to gradually decline. There will be an opportunity to utilise the gas cap, estimated at 70-80 BCM, after the recoverable oil reserves are exhausted.

South Bassein

The Bassein field is India's largest free gas field and was discovered in 1976. Development of the field was delayed by slow progress in planned industrial development in western India. Production from Bassein started in 1986 and reached a level of 30 MMSCMD by 1998. Recent production from the field has been better than anticipated, indicating the possibility of more in place reserves.

Panna - Mukta - Tapti

These fields were discovered by ONGC during 1976/77 but were not developed. Panna is a small highly paraffinic oil field producing sour gas, Mukta is also a small oil producing field, while Tapti is a free gas field. Enron has indicated that the Tapti field may produce gas upto 17 MMSCMD. This is considered optimistic and a figure of 8/9 MMSCMD appears to be achievable.

North and South Gujarat

The Gujarat region is the second most important gas producing region in India. Production from the North Gujarat and South Gujarat fields has increased steadily from less than 1 MMSCMD in 1970/71 to 9 MMSCMD in 1998/99.

Assam

Gas production from Assam stands at 5.6 MMSCMD at present.

Gas supply infrastructure

Infrastructure for gas supply to processing terminals is located mainly in the western offshore region. Sub-sea pipelines connect the various Western Offshore fields to three terminals located on the west coast.

The terminal at Uran, near Mumbai, can handle 16 MMSCMD of sweet gas. After separation of NGL and LPG the residual gas is delivered to consumers through a pipeline network.

The terminal at Usar, south of Uran, can handle 41 MMSCMD cm/day of gas. A gas supply pipeline feeds Usar with the surplus gas which cannot be handled at the Uran terminal.

The Hazira terminal in South Gujarat is equipped with gas sweetening facilities for treatment of sour gas from South Bassein and other offshore fields. Apart from NGL and LPG separation facilities, fractionation facilities have been recently put up at Hazira to produce naphtha and kerosene from NGL. The residual gas is distributed through the HBJ pipeline and a local area network.

Coal Bed Methane (CBM)

A conservative estimate pegs CBS resources at 850 BCM. The work programme for exploiting CBM, as presented by the Directorate General of Hydrocarbons, indicates a lead time of 13 years to commercial production. Gas production in the initial years (2015) is expected to be 11.6 MMSCMD.

Gas supply-demand projections

Based on the most likely estimates of gas demand, the gas supply-demand balance is summarised in Table 1.6.

Table 1.6 Projected gas supply-demand balance (MMSCMD)

Year	Gas demand (MMSCMD)	Domestic gas availability (MMSCMD)			Gas imports	
		Natural gas	CBM	Total	(MMSCMD)	(MMT)
1999	59.4	65.2	-	65.2	-	-
2005	102.7	64.8	-	64.8	37.9	10.0
2010	127.6	64.4	-	64.4	63.2	16.8
2015	150.8	36.7	11.6	48.3	102.5	27.3

Gas availability excludes gas for captive use, LPG shrinkage, other non-energy uses and offtakes by ONGC

These projections indicate an import dependence of the order of 37% by 2015, 50% by 2010 and 68% by 2015.

Chapter 7 Gas imports

Proposals for gas pipelines to India

A summary of proposed gas pipelines to India is provided in Table 1.7. The proposals for gas supply from Oman, Iran, Turkmenistan and Bangladesh have been mired in political and technical uncertainties. While the proposals for piped gas from Oman and Turkmenistan have been abandoned, the Iran India pipeline has recently been given a fresh lease of life. There are also expectations that after elections in Bangladesh later this year, the issue of gas supplies will be discussed between the Indian and Bangladeshi governments with a greater sense of urgency.

Table 1.7 Summary of proposed gas pipelines to India

Name of pipeline	Promoters	Gas field	Routing	Terminal point	Capacity	Estimated project cost	Status
1. Oman-India pipeline	Oman Oil Co.	Sayh Rawl	Seabed. Maxm depth 3500 m	Bachau in Gujarat	20 BCM per annum	$ 5 billion	Abandoned due to deep sea technological problems and insufficient reserves
2. Iran-India pipeline	National Iranian Oil Co.	South Pars	a) Onshore via Pakistan - 2657 km	Linking with the HBJ pipeline in Rajasthan	To be decided	$ 6 billion approx.	Detailed feasibility studies for both routes being undertaken. India wants Iran to guarantee security of the pipeline and delivery of gas to India
			b) Deep sea offshore pipeline avoiding Pakistan	Linking with the HBJ pipeline in Gujarat	To be decided	$ 18 billion approx	
3. Turkmenistan-India pipeline	UNOCAL-led consortium	Daulatabad	Via Afghanistan and Pakistan (Multan) - 1900 km	Linking with the HBJ pipeline in Rajasthan	n.a	$ 2.5 billion upto Multan	Abandoned due to political turmoil and unrest in Afghanistan
4. Bangladesh-India pipeline	a) UNOCAL	Bibiyana	Across W. Bengal and UP - 1350 km	Linking with the HBJ pipeline in UP	5 BCM per annum	$ 1.5 billion	It is hoped that after elections in Bangladesh the new government will permit gas exports to India Possibly UNOCAL and/or SHELL will deliver gas at the border and GAIL will build the pipeline within India and market the gas
	b) SHELL	Sangu	Across W. Bengal and UP - 1350 km	Linking with the HBJ pipeline in UP	5 BCM per annum	$ 1.5 billion	

Proposed LNG terminals in India

A summary of the proposed terminals is provided in Table 1.8. Some of these proposals are at the conceptual, drawing board or feasibility report stage; others are awaiting environmental clearance and/or financial closure; a couple of proposals have some serious issues to resolve before they can go ahead. At this stage it appears that the Dahej terminal of Petronet LNG and the Shell terminal at Hazira have a head start. It is reasonable to expect that an import capability of 18 MMTPA of LNG will be available by the year 2005. The absorption of the entire output of these terminals is a matter of some concern as they are all located to feed only the western and northwestern regions of India. Though the capacity of the HBJ pipeline is to be expanded to 60 MMSCMD, equivalent to 16 MMTPA of LNG, it will still be handling a fair quantity of gas from the Western Offshore fields. Therefore development of networks and markets in Gujarat and Maharashtra and along the route of the HBJ pipeline need to be accorded a high priority. Even then the terminals will not be able to operate at full capacity in 2005 as the projected all-India import requirement in 2005 is only around 10 MMT. A detailed examination, which is beyond the scope of the present study is, therefore, very necessary.

Meanwhile, the prospects of the proposed gas pipelines from Bangladesh and Iran will become clearer so as to enable a rational determination of the quantum of additional LNG import capacity required. Promoters of the proposed terminals at Kakinada (2.5 MMTPA), Gopalpur (5 MMTPA) Jamnagar (5 MMTPA) and Pipavav (3 MMTPA) will need to proceed cautiously while firming up their plans and proposed plant capacities and also take into account development of offshore discoveries especially on the eastern seaboard. Nonetheless, it would appear that gas import capability of the order of 30 MMTPA may well progressively develop by the year 2015 to meet the projected import requirement of 27 MMT.

Table 1.8 Summary of proposed LNG terminals

Location	Promoters	Source of LNG	Tanker receiving capacity	Initial terminal capacity	Project cost	Marketing of regasified LNG	Status
1. Jamnagar	Reliance group	LNG plant to be set up in Iran by NIOC/BP/ Reliance	135,000 cu m.	5.0 MMTPA	Not yet evaluated	Reliance will market themselves	Project at very preliminary stage. Earliest commissioning 2007
2. Pipavav	Gujarat Pipavav LNG Ltd.	Potential suppliers short listed	135,000 cu m	3.0 MMTPA	n a.	To be linked to HBJ at Hazira by pipeline Marketing plans not known	Multi-cargo port built. LNG jetty to be built. Progress on terminal slow. May become unviable if other proposed Gujarat terminals make considerable headway
3. Dahej	Petronet LNG Ltd	Rasgas of Qatar	135,000 cu.m	5.0 MMTPA	$ 537 million	GAIL 60%, IOC 30%, BPCL 10%	All clearances in hand. EPC contract awarded. High breakwater to counter severe maritime conditions. Financial closure by end 2001. Estimated commissioning - 2004
4 Hazira	Shell	Own sources	145,000 cu.m.	5 0 MMTPA	n.a.	Shell	All clearances in hand. Shell is developing Hazira as a multi-cargo port. Estimated commissioning - 2004
5. Trombay	India Natural Gas Co Pvt. Ltd (TPC/TGPI/ GAIL)	Middle East source where Total Fina Elf have equity stake	100,000 cu.m.	3.0 MMTPA	$ 350 million	TPC will take 1.0 MMTPA for their power plant at Trombay. GAIL will market balance	Ministry of Environment & Forests approval awaited. Financial closure expected end 2001. Estimated commissioning 2005

Location	Promoters	Source of LNG	Tanker receiving capacity	Initial terminal capacity	Project cost	Marketing of regasified LNG	Status
6. Dhabol	Enron	Oman LNG, Ad Gas of Abu Dhabi and Malaysia LNG Tiga	135,000 cu.m.	5.0 MMTPA	Part of DPC power plant complex. Separate cost not available.	Enron subsidiary Metgas to market balance gas after DPC requirements met	Terminal almost ready. Commissioning uncertain view stand-off between DPC & MSEB.
7 Kochi	Petronet LNG Ltd.	Rasgas of Qatar	135,000 cu.m.	2.5 MMTPA	$ 350 million	GAIL, IOC & BPCL	Ministry of Environment & Forests clearance awaited. Breakwater/jetty to be built Earliest commissioning - 2005
8. Ennore	Dakshin Bharat Energy Consortium	Rasgas	135,000 m.m.	2.5 MMTPA	$ 1500 million includes 1850 MW power plant	1.8 MMTPA for power plant. Balance 0 7 MMTPA to local consumers	Ministry of Environment & Forests & CCEA approval awaited Customers for power not yet fully firmed up. Payment security mechanism from Indian government not yet in place Commissioning date uncertain
9. Kakinada	IOC led consortium	Petronas, Malaysia possible supplier	135,000 cu.m. after dredging of channel	2.5 MMTPA	Cost including 1000 MW power plant not available	Separate JV likely for marketing balance gas after power plant requirement met	Early days yet as detailed feasibility report recently submitted to Andhra Pradesh government
10. Gopalpur	Gopalpur LNG Ltd	Australia LNG	n.a.	5.0 MMTPA	$450 million	Local consumption by 2500 MW power plant and fertilizer plant Balance gas to south and north India by long distance pipelines	Deep-water port at Gopalpur to be developed. Land for terminal to be acquired. Plans to achieve financial closure by 2001 very unlikely.

Chapter 8 Gas transmission infrastructure

In this chapter, the major gas transmission proposals are described in the context of the evacuation of regasified LNG from each of the proposed terminals, augmentation of local area networks and the import of piped gas

Jamnagar LNG terminal

Dahej and Pipavav are located close to the existing pipeline network feeding parts of Gujarat State and the long distance HBJ pipeline. Reliance will not want to bank on the same infrastructure and are considering laying two parallel transmission lines connecting the west and east coast across central India.

Pipavav, Dahej and Hazira LNG terminals

All three terminals are planning to meet the demand in Gujarat through the existing local area networks, which are to be considerably expanded, and to supply north-western and northern India through the HBJ pipeline. While the Dahej terminal is located close to Hazira, a sub-sea pipeline would need to be laid from Pipavav to Hazira.

Gujarat state network

The Gujarat government had framed a Gas Act in 2000 to regulate transmission and distribution of natural gas in the state. The state-owned company, Gujarat State Petronet Ltd (GSPL), is to create a network of 1,500 km pipelines for transporting indigenous and imported gas to major consumer centres in Gujarat at a planned investment of Rs 24 billion ($ 520 million) and to operate it on a 'common carrier' basis. It is understood that Shell, Gaz de France and British Gas have accepted the offer of participating in GSPL's equity by committing $13 million each for a 11% share. Phase I consists in laying a pipeline from the Maharashtra border to Vadnagar in North Gujarat for a total length of 525 km to be completed in 2002. Phase II would involve laying pipelines in the Saurashtra region for a total length of 600 km, to be completed in 2005.

Hazira–Bijaipur–Jagdishpur (HBJ) pipeline

The HBJ pipeline, is the only major gas transmission line in India. It is owned by GAIL and was commissioned in 1986-97. Wet gas from the offshore South Bassein field is fed by 216 km sub-sea lines dia to ONGC's sweetening and fractional separation plant at Hazira. It consists of a 36" line from Hazira to Bijaipur (Vijaipur) which thereafter reduces to 30" with further reduction beyond Auraiya. Spur lines at various points in Gujarat, Rajasthan, Uttar Pradesh, Delhi etc. feed power plants, fertiliser plants and industries. Originally the capacity of the line was 18.2 MMSCMD. The completion of the Gujarat Rehabilitation and Expansion Project (GREP), which involved laying a 505 km x 30" tie-line between Bijaipur and Dadri along with enhancement of compressor capacity, resulted in an expansion of capacity to 33.4 MMSCMD. To cater to LNG imports, GAIL proposes to invest around Rs 30 billion ($ 650 million) to expand its capacity to 60.0 MMSCMD by 2003 by, inter alia, laying a parallel line from Hazira to Bijaipur. A detailed feasibility report of the project has been completed. GAIL is also planning to extend the HBJ pipeline to Ludhiana to cater to the requirements of Punjab and Haryana.

Trombay and Dabhol LNG terminals

Apart from meeting the gas demand of the Tata Power Company at Trombay, Indigas will satisfy the current and projected shortfall in gas production from Bombay High that is currently supplied to the Uran terminal.

Maharashtra state network

GAIL has signed a gas cooperation agreement with the Maharashtra Industrial Development Corporation and the Maharashtra Petrochemical Corporation Ltd for the development of a gas pipeline network and marketing of natural gas in the state. The length of the network is estimated at 1300 km and requires an investment of over Rs 25 billion ($ 540 million).

Enron's plans for gas marketing from Dabhol terminal

While deciding to put up a large LNG import terminal of 5 MMTPA capacity at Dabhol, Enron had planned to market around 3 MMTPA of surplus regasified LNG after meeting DPC's requirement of 2 MMTPA for power generation. They floated a subsidiary company, Metgas, for the purpose of gas marketing and transportation with an initial investment of $ 60 million. The imbroglio over the Dhabol power plant brought all work is a standstill and Metgas staff, who were mainly on land survey work, were asked to resign. Considering that work on the 5 MMTPA terminal is almost complete, this facility will ultimately be commissioned but its ownership may well be in other hands.

Kochi LNG terminal

Kerala state network

GAIL and the Kerala State Industrial Development Corporation (KSIDC) have entered into a gas cooperation agreement for the development of a gas pipeline network and marketing of natural gas in Kerala. Demand for gas in Kerala is likely to be relatively low and GAIL would need to look further afield to be able to absorb the entire regasified LNG from this terminal. Therefore, GAIL is also planning the expansion of their network into Karnataka.

Karnataka state network

GAIL has signed an agreement with the Karnataka State Industrial and Infrastructure Development Corp (KSIIDC) to study the setting up a gas pipeline to serve various end users in Karnataka. Tentative plans are to lay a pipeline from Kochi along the coast to Kasargode in Karnataka where it will bifurcate. One arm will extend to the port of Mangalore and the other to Bangalore. An investment of Rs 20 billion ($ 435 million) would be required for the 1000-km pipeline network and other facilities.

Ennore LNG terminal

The 2.5 MMTPA LNG terminal will essentially meet the requirements of the 1850 MW power plant at Ennore and Madras Chemical & Fertilizers Ltd. with only about 28% of the regasified LNG being sold to other industries and consumers through a local area network. Therefore, there are no plans to set up a transmission pipeline out of Ennore.

Kakinada LNG terminal

It is early days yet to speculate on the requirement of a gas transmission pipeline. However, the promoters will need to monitor GAIL's plans for expansion of their existing network which is supplied from the offshore Ravva should the need arise to distribute regasified LNG other than in the vicinity of the terminal.

Andhra Pradesh state network

GAIL is planning to market 13.5 MMSCMD of gas by 2002/03, to mostly private power projects in East Godavary, West Godavary, and Krishna districts of Andhra Pradesh. GAIL is currently supplying 3 MMSCMD of natural gas to 550 MW of power generation capacity in the state. Andhra Pradesh has been allocated 5

MMSCMD of gas and will get another 7 MMSCMD after the completion of the gas pipeline projects.

Gopalpur LNG terminal

Two long distance gas pipelines are proposed to be established:

Gopalpur–Cuddalore pipeline

This pipeline is projected to run 1250 km southwards, from Gopalpur to Cuddalore, parallel to the eastern coast linking the state of Andhra Pradesh to Tamilnadu and Karnataka. It will have a spur nearly 300 km long to Hyderabad and another spur of 350 km to Bangalore.

Gopalpur–Kolkata–Auraiya pipeline

The second pipeline, over a similar length of 1250 km, will connect Gopalpur with Kolkata in West Bengal and traverse through the states of West Bengal, Jharkhand, Bihar and Uttar Pradesh, linking up with the HBJ pipeline at Auraiya. The plans to lay the pipeline to UP via Kolkata is also to stake a claim for transmitting imported Bangladeshi gas should the source materialise sometime in the future. With Unocal and Shell also planning to bring gas from Bangladesh to India, an agreement between these companies and possibly GAIL also, would be necessary so that a single line can be constructed to the markets in North India eventually linking up with the HBJ pipeline.

All-India gas grid

Considering the current development status of each of the LNG terminal proposals, the location of markets and the relative economics of the various fuels, it is anticipated that the networks will be developed in three phases as follows:
Phase I (by 2005)

- Gujarat state network - Phase 1
- HBJ pipeline expansion
- Andhra Pradesh state network

Phase II (by 2007)

- Gujarat state network - Phase 2
- Maharashtra state network
- Kerala state network
- Karnataka state network - Phase 1
- Gopalpur - Cuddalore pipeline

Phase III (between 2008 and 2015)

- Karnataka state network - Phase 2
- Gopalpur - Kolkata - Auraiya pipeline

Though the various gas transmission pipelines are being proposed and planned independently, if they all materialise India will have a gas grid connecting the northern, southern, eastern and western regions of the country by 2015. The HBJ pipeline measures 2300 km and additions to the network of about 5700 km is envisaged, making a total length of 8000 km.

Chapter 9 Environmental considerations

The Ministry of Environment and Forests (MoEF) in the Central government and similarly named ministries in the state governments are the principal nodal agencies for all environment-related matters. MoEF is responsible for providing environmental clearance for all major projects in the public and private sector on the basis of a review of the Environmental Impact Assessment (EIA) reports and through its regional offices for monitoring compliance with conditions attached to such clearances. The basic executive authority under the environmental laws is vested in the Central Pollution Control Board (CPCB), the State Pollution Control Boards (SPCBs) and the Pollution Control Committees of the Union Territories. The mandate of the CPCB is to set environmental standards and co-ordinate the activities SPCBs. The implementation of environmental laws and their enforcement are the responsibility of the SPCBs.

Power sector

Air emissions

In India, the CPCB has prescribed emission standards for particulate matter and gaseous pollutants from thermal power plants. The CPCB has not yet fixed any emission standards for SO_2, but has prescribed stack height norms. For NO_X emissions, CPCB is in the process of formulating appropriate standards for coal-based plants. It has already prescribed standards for NO_X emissions for natural gas and naphtha based thermal power plants.

Solid waste

The Ministry of Environment and Forests, Government of India, has stipulated that all new coal-based power plants should indicate a plan for utilization of the ash while submitting the Environmental Impact Assessment (EIA) / Environment Management Plan (EMP) for approval.

Waste water

CPCB has prescribed a set of guidelines for effluent discharge from various sources, namely, condenser cooling water, boiler blowdowns, cooling tower blowdowns and ash pond effluent from thermal power plants. All the effluents must be neutralized and treated before being discharged into waterways. Compared with World Bank guidelines CPCB standards are comparable for zinc and iron and less stringent in case of all other parameters.

Industry

The government has identified 17 categories of industries as highly polluting industries for monitoring and regulating air and water pollution. MoEF has developed standards for regulating emissions from various industries. Discharges of industrial effluents are regulated through Indian Standard Codes.

Transportation

Emission standards

Vehicular emission standards were first set in 1986 by the CPCB for both petrol- and diesel-driven vehicles. These were later revised in 1987 and 1989. However, these emission standards are with reference to the volume of air. They do not constitute mass emission norms, which were first announced in 1991 for petrol vehicles and in 1992 for diesel vehicles. The next stage of mass emission norms, Euro I was initiated in 2000. The third stage, Euro II norms, will come into effect in 2005.

Comparison of standards

The chapter provides a comparison between European Council, the World Health Organization and India on guidelines and standards for sulphur dioxide, nitrogen dioxide and carbon monoxide. Environmental standards for thermal power plants, selected industries and transport vehicles are also listed along with effluent standards for thermal power plants.

Judicial activism

There has been an increase in the number of public interest litigations (PILs) filed by the public and NGOs over the last few years. A series of writ petitions have been filed by environmentalists in the High Courts and in the Supreme Court against ineffective action on the part of the government in protecting the environment. On the basis of extensive hearings, the courts have issued a wide range of directives to various authorities. Two case studies, one relating to use of clean fuels such as CNG for 3 wheelers, taxis and buses in Delhi and the other, the use of natural gas in foundry units in Agra, have been provided in the chapter. They illustrate that while it is relatively easy for units such as power plants to provide the necessary technical infrastructure to comply with air and effluent standards, the same is not the case with the small scale industry and transport sector. In both cases the switch to gas was mandated by the Supreme Court of India. However, a number of technological and other problems have arisen which considerably delayed the change over. As stated in one of the case studies "the government should aim at developing stringent emission standards and ensuring strict compliance. It is best to leave the choice of fuel and technology to the vehicle manufacturers and fuel suppliers".

Chapter 10 Investment profile

Import requirements

Imports have been estimated at 102 MMSCMD or 27 MMTPA. It is assumed in this chapter that matching terminal capacity of 30 MMTPA will be constructed and be operational by 2015, even though the collective capacity of the terminals being planned currently is 38.5 MMTPA. Should any piped gas proposal materialise, the cost of the pipeline and other infrastructural costs will need to be included with a corresponding scaling down of liquefaction, shipping and regasification costs for LNG.

Investment projections

Based on current typical cost elements for a 2.5 MMTPA LNG chain the total investment required is given in Table 1.9 below.

Table 1.9 Investments in a 30 MMTPA LNG chain

	$ million	Rs billion	%age	Remarks
Upstream	2,400	110	12	Outside India
Liquefaction	7,560	355	38	Outside India
Shipping	2,200	103	11	Outside India with some Indian equity participation
Regasification	3,240	152	16	Within India
Transmission*	4,400	202	22	Within India
Total	19,800	922	100	

Upstream and Liquefaction

Some of the capacity required already exists by way of facilities that are operational but not working to full capacity. Also, some capacity is under construction to meet the requirement to start supplies to India by 2004/5.

Shipping

Based on the cost of $158 million each for the two tankers under construction for Petronet LNG and a projected requirement of around 14 tankers to service India's import requirement of 30 MMTPA LNG, the total shipping cost has been determined.

Regasification

Typically, regasification projects have a debt-equity ratio of 70:30, which would indicate a total debt component of about $ 2270 million for the proposed investments.

Promoters typically employ project financing with limited recourse to mitigate project risks. Typically, some possible concerns of lenders relating to timely construction, capabilities of O & M contractor, suitability of chosen equipment, unexpected costs, sufficiency of throughput at rates to assure debt service and political or cross border risks are listed in the chapter. Mitigating these risks usually involves proving the reliability of EPC contracts, O&M contracts, sales agreements, sovereign guarantees, resource studies, equipment performance data and setting sufficient sinking funds to cover unexpected problems. Sponsors also consider risk mitigation by arrangement of debt facilities from multilateral institutions and international export credit agencies.

Transmission and distribution

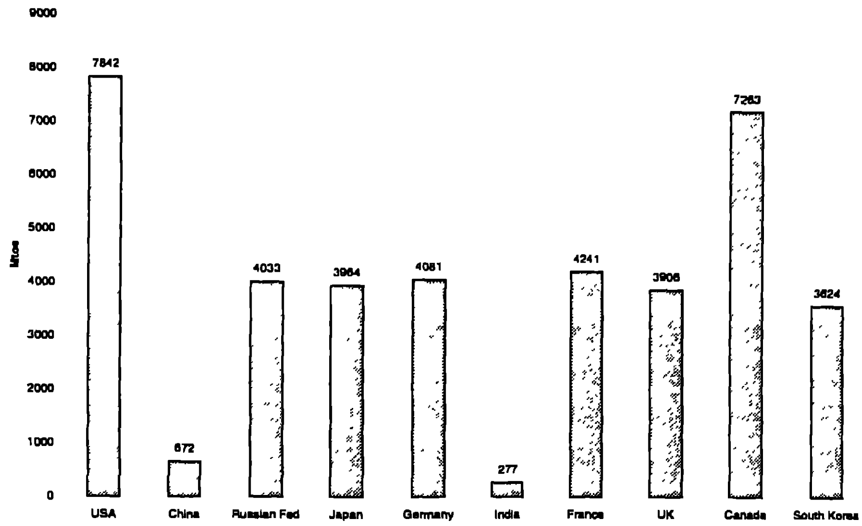
GAIL has indicated investment plans of about Rs 100 billion over the next few years on various schemes. These include about Rs 30 billion ($650 million) for increasing the capacity of the HBJ pipeline system to 60 MMSCMD and Rs 6 billion ($130 million) on setting up new pipelines in the Krishna-Godavari and Cauvery basins. The Gujarat State Petroleum Corporation has set up a separate company, Gujarat State Petronet Ltd (GSPL) to develop a distribution network spanning some 1500 km at a cost of Rs 24 billion ($520 million). More specific plans are likely to be announced once the proposed LNG terminals reach financial closure.

2 The energy scenario

Introduction

Since the initiation of the Five-Year Planning system, the country has exhibited considerable progress with the economy registering an annual growth rate of about 4% since 1950. Sustaining this growth warranted an increasing reliance on commercial energy, which increased from 17 Mtoe[a] in 1950 (MoPNG, 2000) to 276 Mtoe in 1998/99 (TERI, 2000), thereby registering a growth of 5.8% per annum. While India is currently the sixth largest energy consumer in the world, per capita[b] energy consumption in India is the lowest in the top ten energy consumers (Figure 2.1). Indian energy demand is, thus, expected to increase considerably over the years to come.

Figure 2.1 Per capita energy consumption: 1998 (Mtoe)



There is a heavy reliance on coal as an energy source accounting for about 57% of the primary energy supply in 1998/99 (Figure 2.2).

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[a] Commercial energy only. Since statistics are primarily available for commercial energy use, further references in this chapter relate to commercial energy use only, unless explicitly stated otherwise

[b] Estimated from energy consumption figures as reported in BP Statistical Review of the World Energy System and population figures in World Development Indicators

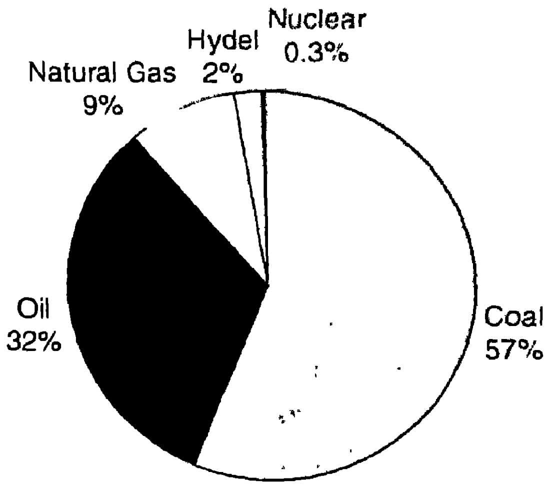

Figure 2.2 Primary energy mix: 1998/99

While the share of oil at 32% is close to the world average, the share of gas at 9% is far below the world average of 23%. As environmental pressures mount, gas can be expected to play a more dominant role in the country's fuel mix, primarily by replacing coal use.

The industrial sector accounts for about 46% of the country's energy requirements (TERI, 2000). Just a few energy intensive industries, viz., fertilisers, aluminium, textiles, cement, iron & steel and pulp and paper account for 65% of the total industrial energy demand. Energy consumption by the transport sector, the second largest energy consuming sector, is 22% of the total energy. High Speed Diesel (automotive diesel) and Motor Spirit together account for 92% of the energy consumed in the transport sector.

The road sector is the dominant mode of transportation, as it makes up 80% of the passenger movement and 60% of the freight trade. Figure 2.3 indicates the sectoral energy consumption in 1998/99.

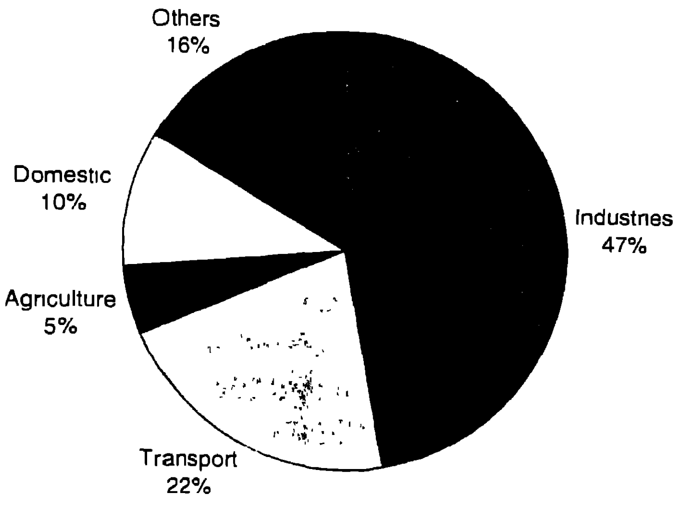

Figure 2.3 Sectoral energy consumption: 1998/99

Role of traditional fuels

The rural sector accounts for about 75% of the total population. It is estimated that 94% of the rural energy use is from traditional bio-fuels like firewood, chips and dung cakes (TERI, 2000). Altogether, bio-fuels account for 40% of the energy consumed in the Indian residential sector.

There are, however, variations in traditional energy consumption patterns across sectors, i.e., rural and urban and within sectors across income classes. According to the 50th NSSO (National Sample Survey Organisation) round, while 78% of the rural households reported using firewood as a primary source for cooking, the corresponding figure for the urban sector was only 29%.

The average rural MPCE (Monthly Per Capita Expenditure) was estimated at Rs 281 ($ 9) (NSSO, 1997). Of the 43% of the rural population with MPCE less than Rs 210 ($ 7), 81% of the population used firewood as a primary source of cooking energy. The affluent rural with MPCE above Rs 560 ($ 18), though accounting for only 7% of the total rural population, had a higher reliance on commercial fuels like LPG and kerosene. In this class, only 58% of the households used firewood as a primary source of cooking energy.

Energy consumption patterns are thus expected to change substantially with economic development. Reliance on traditional fuels would reduce with both the ongoing rural-urban migrations and the transition to higher income categories within the rural areas.

Structure of the petroleum sector

The Indian constitution provides legislative control of the energy sector to the Central Government, with the exception of power, which is a "concurrent" subject, i.e. both the Parliament and the state legislatures have the authority to legislate on the subject. There is no overarching ministry that deals with all energy issues. Legislative control is exercised by the Government through the Ministries of Power, Coal, Petroleum & Natural Gas, Non-Conventional Energy Sources and the Department of Atomic Energy.

The Ministry of Petroleum & Natural Gas (MoP&NG) oversees the entire chain of the oil and gas industry: exploration & production of crude oil and natural gas; refining; distribution & marketing of petroleum products and natural gas, etc. The legal framework for the regulation of exploration and production of oil and gas is provided by the Oilfields Development and Regulation Act, 1948 and the Petroleum and Natural Gas Rules, 1959. The downstream hydrocarbons sector is regulated by the Petroleum Act, 1934 and various control orders under the Essential Commodities Act, 1955.

Exploration & production

Exploration and production (E&P) in the country is primarily undertaken by Oil and Natural Gas Corporation Ltd (ONGC) and Oil India Ltd (OIL). The Indian Government has been inviting private participation in E&P since 1993 through exploration rounds, and presently private parties and joint ventures account for about 10% of the total oil and gas production.

In order to boost domestic oil and gas production, the government also announced the New Exploration and Licensing Policy (NELP) in 1999. Details of bids and awards under NELP are provided in Chapter 3.

Refining

The installed refining capacity of the country's 17 refineries is 112 MMTPA. A third of the country's refining capacity is in the private/joint venture sector: the 9.69 MMTPA HPCL (Hindustan Petroleum Corporation Ltd)/A V Birla Group JV at Mangalore, Karnataka and the 27 MMTPA refinery of Reliance Petroleum Ltd at Jamnagar, Gujarat.

Following the recommendations of the Nitish Sengupta Committee on merger of stand-alone refining companies with integrated refining-marketing companies, the Government sold its stake in Kochi Refineries Ltd (KRL) and Numaligarh Refineries Ltd (NRL) to Bharat Petroleum Corporation Ltd (BPCL) and in Bongaigaon Refineries & Petrochemicals Ltd (BRPL) and Chennai Petroleum Corporation Ltd (CPCL) to

Indian Oil Corporation (IOC). With the restructuring, IOC accounts for the share major of the country's refining capacity with a total capacity of 45 MMTPA.

Marketing: petroleum products

Marketing of petroleum products are categorised in two groups: controlled petroleum products - Liquefied Petroleum Gas (LPG), Motor Spirit (MS), Aviation Turbine Fuel[a] (ATF), Superior Kerosene Oil (SKO) and High Speed Diesel (HSD); and decontrolled petroleum products. While there are no restrictions on sales of decontrolled petroleum products, the prices of controlled products are administered by the Government. In addition, transportation fuels, MS and HSD, can be marketed by the public sector companies only, i.e., IOC, BPCL, HPCL and IBP. The Government had allowed parallel marketing of LPG & SKO in 1993, under which imports of these products were decanalised and private parties were allowed to import and market them at market determined prices.

The Indian petroleum sector is expected to be deregulated by 1st April 2002. Post-deregulation, any company would be free to market transportation fuels subject to investments of Rs 20 billion ($ 434 million) in refining/other industry infrastructure or annual crude oil production of 3 MMT.

Marketing: natural gas

Natural gas is marketed primarily by the Gas Authority of India Ltd (GAIL). GAIL is the largest organisation in India handling post-exploration activities relating to transmission, processing, distribution and marketing of natural gas and its fractions and by-products. GAIL procures natural gas from ONGC, OIL and joint venture consortia in Southern India and the Western Offshore region. GAIL owns and operates the country's only trunk pipeline system - the 2300 km long Hazira-Bijaipur-Jagdishpur (HBJ) pipeline, transmitting 33.4 MMSCMD of gas from the west coast of India to the central and northern parts of country.

Following the commissioning of the HBJ system, the Government transferred to GAIL about 725 km of existing pipelines that had been constructed and operated by ONGC. Pipeline networks owned by gas consumers, totalling 320 km, are also operated by GAIL. In addition, GAIL has laid additional networks in Maharashtra, Gujarat, Rajasthan, Andhra Pradesh, Tamil Nadu, Pondicherry, Assam and Tripura totalling 600 km.

Gas is also being marketed by smaller regional companies - by Mahanagar Gas Ltd (MGL), a joint venture between GAIL and British Gas in Mumbai, Maharashtra;

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[a] ATF has been decontrolled w.e.f 1st April 2001

by Gujarat Gas Company in the cities of Surat, Bharuch and Ankleshwar in Gujarat; by the Baroda Municipal Corporation in the city of Baroda, Gujarat; and by Indraprastha Gas Limited (IGL), a joint venture between GAIL, BPCL & Government of National Capital Territory of Delhi in Delhi.

Energy sector profiles: reserves, production, demand

Natural gas

India's balance recoverable reserves of natural gas stand at 628 BCM. With gas production in 1999/00 at 28 BCM, the reserves to production (R/P) ratio is only 22 years. The three main producing basins in the country, the Western offshore region, the Cambay basin in Gujarat, and Upper Assam region, are in the mature phase of exploration. The Western offshore region accounts for about 60% of the total gas production in the country. Though private/JV companies started gas production only in 1995/96, their current share in the total gas production exceeds 10%. Trends in region-wise production of natural gas are summarised in Table 2.1.

Table 2.1 Region-wise gas production (MMSCMD)

Region	1980/81	1990/91	1995/96	1996/97	1997/98	1998/99	1999/00
Onshore:							
Gujarat	2.3	4.6	7.9	8.0	8.5	8.7	8.5
Assam/Nagaland	2.3	5.5	5.2	5.3	5.5	5.6	5.7
Arunachal Pradesh		0.1	0.1	0.1	0.1	0.1	0.1
Tripura		0.2	0.4	0.4	0.5	0.8	1.0
Tamil Nadu		0.2	0.3	0.3	0.3	0.3	0.4
Andhra Pradesh		0.1	1.9	2.2	2.8	3.3	3.7
Rajasthan			0.0	0.0	0.4	0.4	0.4
Sub-Total	**4.6**	**10.7**	**15.7**	**16.3**	**18.1**	**19.3**	**19.7**
Offshore	1.8	38.6	45.4	46.0	49.6	48.0	48.7
Private/JVCs			0.9	1.4	4.6	7.9	9.5
Total	**6.5**	**49.3**	**62.0**	**63.7**	**72.3**	**75.1**	**77.9**

Gas sales grew at an average annual rate of 7.1% over the last decade. The bulk of the sales were to power generation and as feedstock in fertiliser production. Table 2.2 summarises trends in gas consumption.

Although gas demand has been rising steadily, domestic gas availability is expected to decline in the future. Estimates on domestic gas availability have been presented in the report of the Sub-Group on Development and Utilisation of Natural Gas, constituted under Group on India Hydrocarbon Vision 2025. The Sub-Group's has projected domestic gas availability to decline from 78 MMSCMD currently, to 36 MMSCMD by 2020, in the baseline scenario.

Table 2.2 Trends in sectoral gas use (MMSCMD)

Sector	1980/81	1990/91	1995/96	1996/97	1997/98	1998/99	1999/00
Power generation	1.3	10.0	18.7	19.0	22.2	23.9	25.0
Fertiliser production	1.7	15.4	20.8	20.9	24.0	24.3	24.4
Industrial fuel	0.4	2.3	6.3	7.2	8.5	8.2	6.9
Domestic use	0.0	0.1	0.5	0.5	0.6	0.5	0.7
Others	0.9	7.3	3.2	3.4	3.7	4.7	8.2
Total	**4.4**	**35.0**	**49.6**	**51.0**	**58.9**	**61.6**	**65.2**

The Government is keen on exploring alternative domestic gas supply sources, primarily gas hydrates and Coal Bed Methane (CBM). While the programme for development of gas hydrates is still at nascent stages, a start has been made with regards to exploitation of CBM resources estimated at 1000 BCM. Seven CBM blocks were put on offer in April 2001. Two are located in Jharkhand (Bokaro and North Karanpura), three in Madhya Pradesh (East & West Sohagpur and Satpura) and one each in Rajasthan (Barmer) and West Bengal (Raniganj). Exploitation of these would be structured on a revised model contract, which is a modified version of the NELP. Unlike the traditional profit sharing contract these blocks are being offered under a production linked programme. Estimated "in place" reserves of these blocks are summarised in Table 2.3.

Table 2.3 Estimated in-place gas reserves in CBM blocks on offer (BCM)

Block	Reserves
Raniganj	42
Bokaro	45
North Karanpura	62
East Shogapur	49
West Shogapur	37
Satpura	18
North Barmer	9

Given the uncertainty associated with exploration and production projects, gas imports are inevitable. A number of proposals for gas imports, via pipelines and as Liquefied Natural Gas (LNG) are under consideration. While there are uncertainties associated with pipeline imports, a number of LNG projects is at various stages of implementation. Details of India's gas import options and the status of projects under consideration are presented in Chapter 6.

With expectations that gas imports, primarily LNG, would materialise by 2005, a number of companies has announced plans for gas based additional capacity (new/expansions), both in power generation and fertiliser production. Chapter 5 give details of these projects and the long-term forecasts of gas demand, which are summarised in Table 2.4.

Table 2.4 Preferred gas demand projections(MMSCMD)

Year	Power	Fertiliser	Industry	Transport	Domestic	Total#
1999	25.0	24.4	9.1	0.1	0.7	59.4
2005	55.9	33.2	11.9	0.5	1.3	102.7
2010	69.3	40.3	15.6	0.7	1.7	127.6
2015	78.8	46.3	21.9	1.0	2.7	150.8
CARG	7.4%	4.1%	5.7%	15.4%	8.9%	6.0%

* Short-term estimates (supply driven)

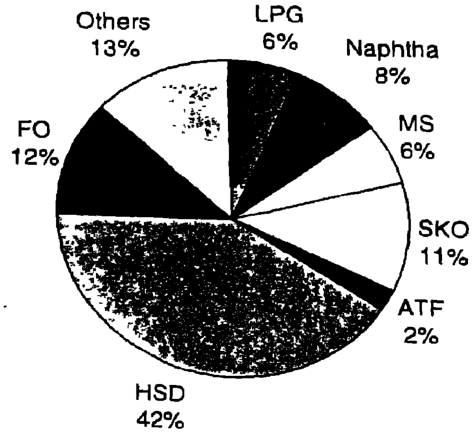
Gas for captive use, LPG shrinkage and other non-energy uses (5.8 MMSCMD in 1999) ignored in forecasts

Petroleum

Indian sedimentary basins beyond the 200m isobath line cover an area of 3.14 million sq. km. (DGH, 1999). About 41% of the Indian sedimentary basins still await exploration. Balance recoverable reserves for crude are estimated at 658 MMT, while crude oil production in 1999/00 stood at 31.95 MMT (MoP&NG, 2000). Crude oil imports in 1999/00, excluding those by private refineries, aggregated 44.99 MMT.

The total consumption of petroleum products in the country in 1999/00 stood at 96.29 MMT. Sales by national oil companies accounted for 94% of the total sales, the rest being marketed by private parties. HSD sales accounted for about 42% of the volume (Figure 2.4).

Figure 2.4 Product-wise sales of petroleum products: 1999/00



The 6% growth rate in demand for petroleum products over the last decade was arrested in 2000/01. Sales of petroleum products by public sector oil companies during 2000/01 increased marginally by 0.1% to 90.2 MMT as compared to that in 1999/00 (ET, 2001). The slowdown in demand is attributed to a range of factors ranging from a fall in agricultural demand to a continuing economic slowdown, but is not expected to impact the long term projections on demand for petroleum products, which retain a healthy growth rate of 5.5%. Demand projections of petroleum products, undertaken by the Group on India Hydrocarbon Vision 2025 set up by the Indian Government in 1999, are summarised in Table 2.5.

Table 2.5 Long-term projections on demand for petroleum products, refining capacity and crude requirements (MMT)

Year	Demand (without meeting gas deficit)	Demand (with meeting gas deficit)	Estimated refining capacity	Estimated crude requirement
1998-99	91	103	69	69
2001-02	111	138	129	122
2006-07	148	179*	167	173
2011-12	195	195**	184	190
2024-25	368	368	358	364

* Assuming 15 MMTPA of LNG import by 2007

** Assuming that by 2012, adequate gas is available through imports and domestic sources

Given the large gap between current domestic crude availability and the projected requirements, the Group recommended a focus on oil security through intensification of exploration efforts and that acreages be secured in countries like Russia, Iraq, Iran and North African countries. ONGC Videsh Limited (OVL), a wholly owned subsidiary of ONGC, is already involved exclusively in foreign ventures - acquisition of acreage and exploration and production operations. It has entered into joint ventures with the IOC and GAIL for exploration in the CIS (Commonwealth of Independent States) and with Reliance Industries Ltd for a discovered oil field (Tuba) in Iraq. In addition OVL has a 45% stake in a upstream gas project in Vietnam, 20% stake in a block in Oman and is considering acquisition of 35% stake in the Balal oil field in Iran (TERI, 2000). OVL has also acquired half of Rosneft's 40% stake in the Sakhalin I project in Russia.

Coal

The Geological Survey of India has estimated India's proven coal reserves at 82 billion tonnes. Total coal reserves are estimated at 212 billion tonnes of which nearly 86% are non-coking coal reserves. India is the third largest producer of coal in the world. Coal India Ltd (CIL) and its subsidiaries account for about 85% of the coal produced in India.

Coal reserves are primarily concentrated in the Eastern region of the country - in the states of Jharkhand, West Bengal, Madhya Pradesh, and Orissa. Additionally, coal reserves are also located in the states of Maharashtra, Andhra Pradesh and some parts of Uttar Pradesh. Indian coal is generally of low quality with high ash content and low calorific value. It predominantly exists in thick seams interbanded with extraneous matter. The best quality of metallurgical coal is found in the mines of Jharia (Jharkhand) and in some mines in Raniganj (West Bengal). However, the mining of coal in these areas is complicated because of the large-scale indiscriminate exploitation of these areas prior to nationalisation of coal companies and the heavy built-up areas over such deposits.

The quality of power grade coal has been deteriorating over the years. Power plants often receive coal with large amounts of ash and shale. In 1997, the Government issued a notification that disallowed use of coal with ash content greater than 34% in power plants located in urban centres, sensitive areas, critically polluted areas and those which are more than 1000 km away from the source of supply. While this order became immediately applicable for power plants under the first three locations, the fourth was to be implemented from 1st June 2001. Since adequate quantity of the requisite quality of coal are not available, coal imports have increased lately. Table 2.6 summarises trends in coal production and imports.

Table 2.6 Trends in coal production and imports (MMT)

Year	Coking Coal			Non-Coking Coal		
	Production	Imports	Availability	Production	Imports	Availability
1992/93	45.2	6.3	51.5	196.8	0.4	197.2
1993/94	44.7	6.8	51.5	204.0	0.6	204.6
1994/95	42.0	10.2	52.1	215.8	1.2	217.0
1995/96	39.9	9.4	49.3	233.5	3.1	236.6
1996/97	40.5	9.8	50.3	245.5	4.5	250.0
1997/98	43.8	10.7	54.5	253.3	6.6	259.9
1998/99	39.2	9.6	48.8	253.1	6.0	259.1

Bulk of the coal is used for power generation (71%), followed by steel manufacturing. Figure 2.5 presents the sectoral coal consumption pattern in 1998/99. Against sales of 289 MMT of coal in 1998/99, the demand for coal is expected to reach 775 MMT by the end of the Tenth Five Year Plan (2011/12) {PC, 2001}. Coal production (non-coking), on the other hand, as seen above has more or less stagnated over the last three years, with an annual growth rate of less than 2%. The output per manshift is Indian mines is significantly lower than

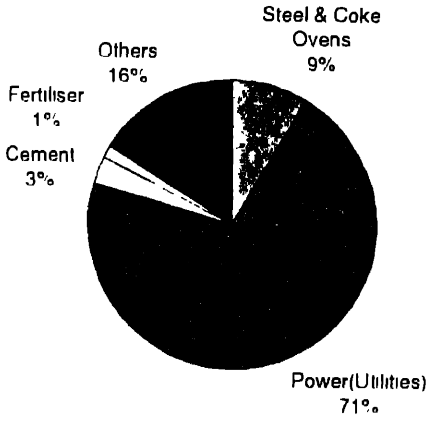


Figure 2.5 Sectoral coal consumption: 1988/99

international standards. Investments in new mining projects has been poor over the last few years. The share of output from opencast mines, which contributed only about 28% of the total production at the time of nationalisation of mines in 1973, is now more than 70%. Over reliance on opencast mining has led to rapid depletion in coal reserves. Exploitation of shallow seams in the past now requires mining of deeper seams, which would eventually lead to high long run costs of coal production.

Given the important position of coal and lignite resources in India's overall energy strategy and the urgent need for development of these resources, the Planning Commission constituted a Committee on "Integrated Coal Policy", which submitted its report in May 1996. The major recommendations included augmentation of domestic coal production by involvement of the private sector, integrating the exploratory efforts for coal and lignite, deregulation of coal prices and distribution of coal, creation of a regulatory body for price disputes etc., setting up more pithead coal/lignite-based thermal power stations, augmenting of railways and port infrastructure facilities, amendments/modifications in various Acts for facilitating private sector participation and expediting project clearance procedures. However, deregulation of the prices and distribution of all grades coal and coal products are the only recommendations implemented so far by the Government. Considering all factors, coal production in India is likely to plateau at about around 600 MMTPA by 2025.

Electricity

The country's installed capacity as on 31st March 2000 aggregated 97,837 MW

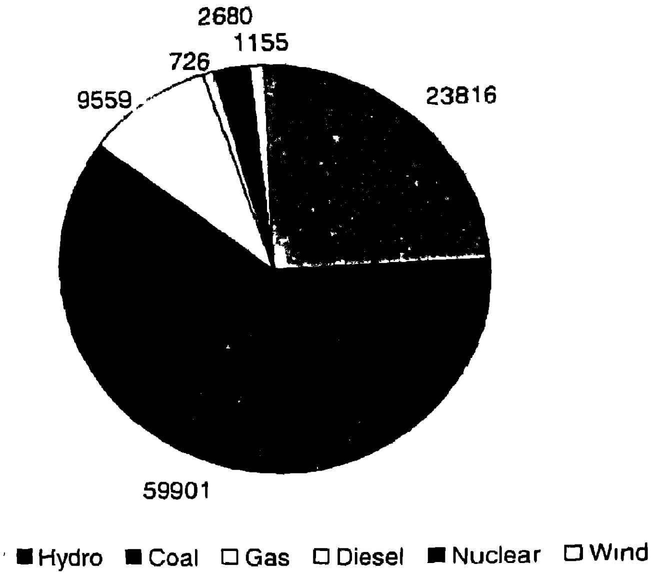


Figure 2.6 Mode wise installed generating capacity (MW)

(TERI, 2000). Details of installed capacity are presented in Figure 2.6. In addition, an estimated 14, 705 MW of captive generating capacity is operational.

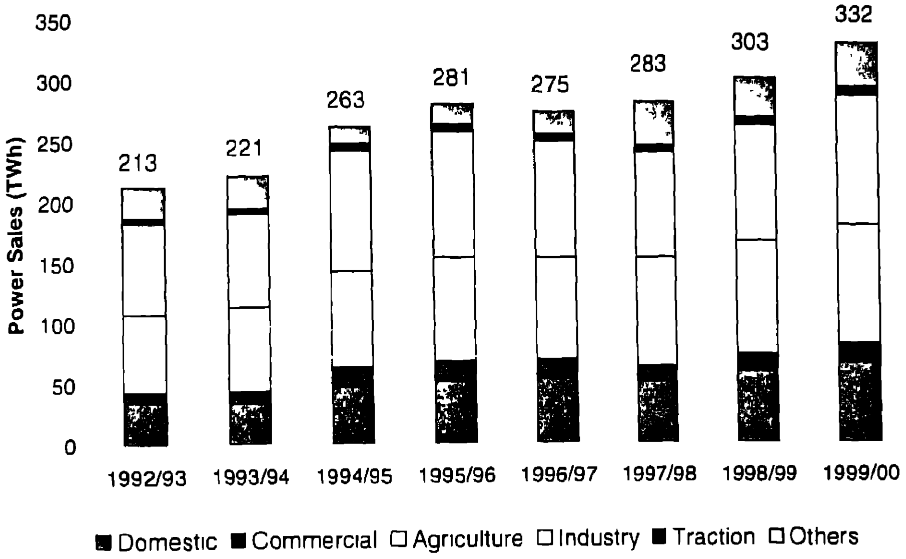
During 1999/00, against energy requirements of 480 TWh and a peak demand of 72, 669 MW, the available energy was 451 TWh and the peak demand met was 63,691 MW (TERI, 2000). The associated energy deficit was 6.2% and the peak deficit 12.4%, both having been reduced substantially during the IX Five Year Plan from 11.5% and 18% respectively at the end of the VIII Plan, i.e., 1996/97.

The IX Plan envisaged a total capacity addition of 40 245 MW: 9820 MW hydro, 29 545 MW thermal and 880 MW nuclear (TERI, 2000). Actual capacity addition of 12,000 MW during the first three years of the Plan (1997/98 – 1999/00), however, has been below targets. The mid-term review of the IX Plan, scaled down the capacity addition target to 28 097 MW.

The transmission & distribution (T&D) system is a serious cause for concern. While T&D losses in 1999/00 were reported at 22%, the actual losses are significantly higher as these include power thefts. Reassessment of T&D losses in Andhra Pradesh, Haryana and Uttar Pradesh revealed actual T&D losses at 51%, 40% and 42% against reported losses of 25%, 32% and 27% respectively (TERI, 2000).

Electricity sales have increased at a healthy 6.4% over the last decade. Sales to the agriculture and industry sectors account for about 30% each of the total sales, while domestic consumers account for about a fifth (PC, 2000). Trends in sectoral power sales are summarised in Figure 2.7.

Figure 2.7 Trends in sectoral power sales (TWh)



There are severe tariff distortions in the power sector. While the agriculture sector accounts for nearly a third of the total electricity sales, the revenues from this sector contribute to only 3.6% of the total realisation due to subsidised tariffs. Subsidies are also extended to domestic consumers, which together with the agriculture sector account for about half of the power sales, but only a sixth of the realisation. On the other hand, the industry and commercial sector account for 80% of the realisation from only a third of the sales. The State Electricity Boards (SEB) are in a poor state of financial health with cost recoveries of the order of 74% only. In 1999/00, while the average cost of generation was Rs 2.8/kWh, the average realisation was only Rs 2.1/kWh (PC, 2000). Commercial losses of SEBs in 1998/99 aggregated Rs 134 billion ($ 2910 million).

Recognising the critical role of the power industry in the country's infrastructure, the Government initiated a series of reforms in 1991 targeted at improving the performance of the industry, corrections of tariff distortions, encouraging participation of the private sector, etc. In 1998, the Government passed a legislation enabling the establishment of independent and autonomous regulatory bodies at the centre and state level. The Central Electricity Regulatory Commission (CERC) was to regulate tariffs of central generating companies and other generating companies. State Electricity Regulatory Authorities (SERC) were empowered to determine tariffs payable for intrastate transmission and supply of electricity. SERCs were also expected to regulate the working of licensees and others involved in the electricity industry in the state. By March 2000, 13 states had set up SERCs.

The 16th Electric Power Survey of the Central Electricity Authority (CEA), projects energy requirements to grow at an annual rate of 6.3% over the period 2001-2017 (Table 2.7).

Table 2.7 All India energy & peak demand forecasts

Year	Energy Requirement (TWh)	Peak Load (MW)
2001/02	529	85132
2006/07	719	115705
2011/12	975	157107
2016/17	1319	212725

Reforms in the power sector are imperative to ensure adequate investments in generation and transmission to meet the growing demand for power in the country.

Renewable energy

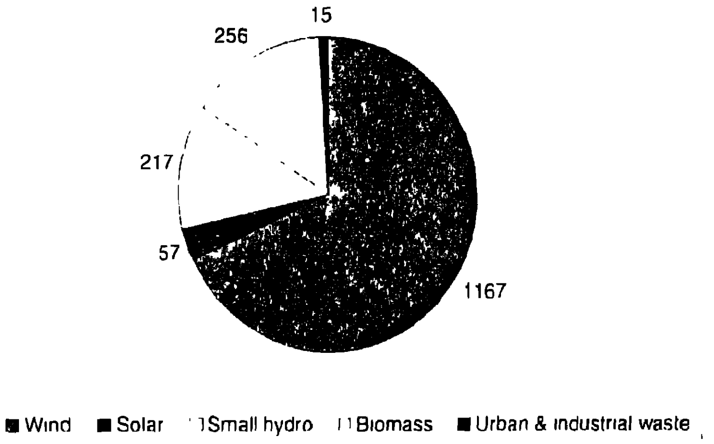
With growing environmental concerns and a recognition of the limited availability of conventional fossil fuel resources, the thrust towards adoption of renewable energy technologies (RET) has gained considerable momentum in India. The Ministry of Non-Conventional Energy Sources (MNES) is actively involved with various programmes related to development, demonstration and utilisation of RETs such as, biogas, biomass, solar energy, wind energy, and small hydro. Estimates of the technical potential for RETs are summarised in Table 2.8.

Table 2.8 Technical potential of RETs

Source/system	Approximate Potential
Biogas plants (nos)	12 million
Improved cookstoves (nos)	120 million
Biomass energy	17 000 MW
Solar energy	20 MW/km^2
Wind energy	20 000 MW
Small hydro	10 000 MW
Ocean energy	50 000 MW

The MNES has issued guidelines to all states regarding use of renewable energy in power generation with a view to increase the penetration of RETs. The cumulative achievement till date accords 1713 MW of generating capacity to renewables (Figure 2.8).

Figure 2.8 Renewables based power generating capacity (MW)



MNES's solar power programme aims at grid quality power generation via solar thermal and solar photovoltaic (SPV) technologies. MNES has proposed to set up a 140 MW Integrated Solar Combined Cycle Power Project with a solar thermal power capacity of 35 MW at village Mathania, Jodhpur district of Rajasthan (MNES, 2001). The combined cycle power plant of 105 MW capacity with supplementary firing during non-sunny hours will be run on naphtha/gas. The SPV initiatives target 1 MW capacity as voltage support at rural sub-stations and in peak shaving in urban areas. So far 15 projects with an aggregate capacity of 1165 KW have been commissioned, while another 10 projects of 500 KW are in various stages of implementation.

While India has large and diverse renewable energy programmes, markets and market-support infrastructure for RETs is still lacking. Product development continues to be largely supply driven rather than being responsive to user needs. The cost of power generation from RETs continues to be high with capital costs ranging from Rs 50 million/MW to Rs 200 million/MW and low capacity factors (15% to 24%) as compared to conventional systems with capital costs of about Rs 40 million/MW and plant load factors in the range of 50% to 70%. Other problem hindering promotion of RETs include poor incentive structures/financing options; lack of indigenous R&D, demonstration and product development; problems in power evacuations; high transaction costs on account of rudimentary market infrastructure, etc.

Despite the above mentioned problems, the potential for RETs in the country is immense. A National Renewable Energy Policy under consideration envisages that 10% of the installed generating capacity should be based on renewables by 2012.

India's future energy scenario

India's energy requirements are expected to increase considerably in the years to come, with higher per capita requirements following economic development and the rising population. Commercial energy requirements would increase further as the rural poor transcend the income ladder and switch from traditional fuels to commercial ones.

These growing requirements compare unfavourably with indigenous energy resources. Current self sufficiency in oil is only about 30%. Though the Government has initiated a series of measures to increase domestic oil production, large scale oil imports are inevitable. Domestic gas production is expected to reduce to less than half the current production levels by 2020. Despite large reserves, production of coal is likely to finally plateau at about 600 MMTPA making coal imports inevitable. With coal resources concentrated in the eastern region of the country, all-India distribution would emerge as a critical problem due to bottlenecks in the transportation system. Growing environmental concerns would drive the switch to cleaner fuels. Renewables are likely to be a major thrust area with the Government planning 10% of the generating capacity by renewable sources by 2012. However, the existing track record has not been very satisfactory and the proposed target seems highly ambitious.

Imports of all fossil fuels are thus inevitable. Even if domestic crude production is raised to 100 MMT by 2025, crude imports are likely to be of the order of 254 MMT, i.e., about a third of the entire current crude imports into the Asia Pacific region. The choice between imports of coal and gas would be governed by inter-fuel economics and availability. A detailed analysis is presented in Chapter 4. Other governing factors would be transportation logistics, environmental concerns, port handling capacity etc. Energy security concerns would require diversification of fuels and supply sources.

3

Energy and fertiliser sectors policies

Natural gas

Opening up exploration and production

Success in oil and gas exploration in India has come in cycles. There have been brilliant discoveries such as the Bombay High and other western offshore fields and there have been periods over which the same amount of physical effort did not produce any appreciable result. By and large, exploration has been in the hands of National Oil Companies (NOCs) - Oil and Natural Gas Corporation Ltd. (ONGC) and Oil India Limited (OIL). Being commercial organizations, their strategy has been to concentrate in areas near producing fields.

The 26 sedimentary basins in India include six Category I basins that have been moderately well explored. The rest of the basins have not been well explored. Of the 3.14 million square km sedimentary basins 67% is unexplored. Of the balance, about half is moderately explored, and the other half is poorly explored. The exploratory drilling intensity is low compared to that of USA.

ONGC and OIL have been known as good finders. However, as they faced the challenge of exploring more difficult areas and the deep waters, the technology gap became critical. According to experts, this gap between the best globally available technology and that used by ONGC is serious and could grow larger. Reserve accretion of oil and gas during the Seventh Five-year Plan (1987–92) exceeded the depletion and the reserves to production (R/P) ratio went up even as the production increased. The Eighth Five-year Plan period (1992–97) started on a poor note. The accretion in the first three years was far short of target and the government decided to launch an accelerated program for exploration (APEX), which had a number of components including:

- A national seismic grid
- Exploration in frontier areas and deep waters

The Eighth plan outlay was also suitably enhanced. The idea behind the national seismic grid was to extend the available seismic data to the areas not yet covered and to upgrade the data quality. Attempts to involve the private sector in seismic surveys through bidding rounds for speculative surveys were not successful.

However, joint venture speculative surveys with participation of the Directorate General of Hydrocarbons (DGH) have opened up 0.4 million-sq. km. DGH has also covered the entire Indian continental shelf upto a depth of 3000 metres through satellite gravity surveys.

In spite of this mid-course correction, reserve accretion targets were not met by the end of the plan period. This was among the factors which redirected attention on supplementing these exploration efforts by bringing in the private sector. Exploration bidding rounds started in 1979, far ahead of the economic reforms of the 1990s, but the early rounds were unsuccessful. The first four rounds were spread over twelve years (1979-91). The next five rounds occurred in just two years (1994-95) and succeeded in generating some interest in the international oil industry. To increase this interest, government decided to award some small and medium sized fields for development in the private and joint sectors respectively. An innovation was also introduced in the ninth round – known as the JV round - to reduce the risk for the private investors by associating ONGC/OIL as partners in these exploration ventures. However, the rigid decision making structures of these NOCs created problems of compatibility and reduced the attractiveness of this innovation. The number of blocks advertised before the launch of the New Exploration Licensing Policy (NELP) and the bids received in the various rounds were as detailed in Table 3.1 below:

Table 3.1 Exploration blocks offered and bids received

Round	Year	Blocks offered	Bids received
I	1979	32	4
II	1982	50	nil
III	1986	27	13
IV	1991	72	24
V	1993	45	15
VI	1994	46	20
VII	1994	45	12
VIII	1994	34	38
JV	1995	34	22

The result of this effort has been that 35 exploration blocks and 30 discovered fields have been awarded to the private sector. Work is in progress in 22 exploration blocks and contracts for some more blocks would be signed soon. Five medium and thirteen small fields are under development, some of which are already producing oil/gas. The total investment brought into the sector so far, mostly in producing fields, exceeds $1 billion. Production of crude oil and natural gas from these fields has increased over the years to about 10% of the total production. The bulk of the reserve accretion through these efforts has taken place around the previously discovered fields.

Although these results are by no means insignificant, there is general agreement that these have not met expectations and a number of reasons are cited for the disappointing results. There was a perception that the blocks with better prospects were reserved for the NOCs and only the high-risk areas were offered to the private investors. The seismic data provided was inadequate in most cases in addition to being old and expensive. The NOCs continued to hold on to the blocks they were awarded on a nomination basis. They also played a decisive role in the delineation of the blocks to be offered in the bidding rounds. These factors reduced the commercial attractiveness of the blocks offered. The incentive structure was designed after a study of practices followed by other countries such as China and Indonesia. Many potential bidders were, however, of the opinion that better incentives were necessary in India to make up for the higher perceived risks.

The other factor, a very important one, was the delays in policy making and implementation of the exploration sector policies. The award of production sharing contracts (PSCs) requires clearance from several ministries, leading to delay. Though there is an empowered committee of secretaries, it had limited success in cutting through red tape. While it should normally take a few months to award these contracts after the receipt of bids, in practice, it took 2 to 3 years. Further, the awards were followed by lengthy negotiations prior to signing of the contract. Even after the contract was signed, many approvals, including the all important exploration license, were required. These also took time to come through.

The NELP (New Exploration Licensing Policy)

With a view to removing these shortcomings, a New Exploration Licensing Policy was formulated by the government in 1997-98 to provide a level playing field in which all parties could compete on equal terms for the award of exploration acreage. The salient features of the NELP are:

- NOCs to compete for acreage
- Fiscal stability provision in the contract
- Model Production Sharing Contract to aid contract negotiation
- Petroleum tax guide to help investors
- Possibility of seismic option in the first phase of the exploration period

Some of the improvements in the fiscal and contractual terms are:

- No payment of signature, discovery or production bonus

- No customs duty on imports required for petroleum operations
- No minimum expenditure commitment during the exploration period
- No mandatory state participation/carried interest by NOCs.
- Freedom to sell crude oil and natural gas in domestic market at market related prices
- Biddable cost recovery limit up to 100%
- Biddable sharing of profit petroleum based on pre-tax investment multiple achieved
- No cess on crude oil production
- Royalty payment for crude oil on ad valorem basis
    - 12.5% for onland areas
    - 10% for offshore areas
- Royalty on deep water areas(beyond 400m bathymetry)
    - 5% for first seven years after commencement of commercial production
- Option to amortise exploration and drilling expenditures over a period of 10 years from first commercial production
- Contribution to site restoration fund fully deductible in same year for income tax
- Liberal depreciation provisions making companies eligible for further tax adjustments
- Infrastructure status: 7 years tax holiday from commencement of production
- Conciliation and Arbitration Act, 1996, which is based on UNCITRAL model made applicable.

The companies are required to bid for:

- Work programme commitment
- Profit petroleum share expected by the contractor at various levels of pre-tax multiple of investments
- Percentage of annual production sought to be allocated towards cost recovery

The main bid evaluation criteria are:

- Technical capability of the bidding company / consortium
- Operatorship experience
- Financial capability of the bidding company / consortium
- Work Programme
- Profit sharing offered by the bidders/s along with proposed cost recovery limit

The first bidding round was launched in 1999. The NELP attracted 45 bids for 27 blocks, from which the MoP&NG approved the award of 25 blocks. Exploration blocks under the Second Round of NELP were offered in December 2000. Altogether, 25 blocks were put on offer in NELP II, including 8 deepwater blocks. By 31st March 2001, the closing date for NELP II, 13 companies submitted bids for 23 blocks - 8 deepwater, 8 shallow water and 7 onland.

This round has also generated quite some interest although the major oil companies have stayed away from the bidding. Reliance and ONGC have emerged as the most aggressive bidders. The MNCs bidding in this round include Cairns which is already active in India, Hardy Oil, Petrom, Heramec and Niko Resources of Canada.

The exploration under the first NELP round has already started producing results. Cairns have found gas in three structures in Cambay offshore and is expecting a much bigger find in offshore KG basin. The other operators in the KG basin are equally upbeat about their own blocks. This optimism is based on a series of gas finds by ONGC recently in the area. Speculations over an offshore giant field are rife. As noted before, the oil majors have not found the offered blocks attractive. This could be on account of possibilities opening up in the Atlantic basin or even the Middle East. This has been a major setback but the disappointment has been relieved to a large extent by the achievements of the smaller operators.

The government is reportedly considering the introduction of continuous bidding as the logical next step but no announcements have been made as to when this would be introduced.

Promoting the import of LNG

Faced with a widening gap between the demand and supply of natural gas, the government has considered a number of options for importing gas. The stress was on imports through pipelines but the pipeline projects failed to take off mainly on account of geo-political problems. In 1996 the government decided to encourage the import of LNG and formed Petronet LNG by bringing together the public sector giants - IOC, ONGC, GAIL and BPCL. No restrictions were put on private imports and within a short time a large number of projects were proposed and approved. Such was the rush of projects that the government contemplated restricting the growth. The need to do so may arise mainly for two reasons. First, import of LNG means foreign exchange outgo. Import of 15 MMTPA would cost around $2.5 to $3.0 bn annually at a crude oil price of $18/bbl. Although the forex reserves are comfortable right now, LNG contracts typically last 15-20 years and may put pressure on these reserves if exports do not do well. Secondly, gas is used mostly for power generation and production of urea. Both the commodities are heavily subsidised by the government - power by the state governments and urea by the central government. Any increase in LNG use or the LNG price therefore increases the subsidy burden. Indications are that the government will make serious attempts to contain and reduce the subsidy burden.

Regulation of the LNG industry

The government has considered the need to regulate the location and size of the LNG terminals, put a cap on the number of proposals to be approved in a particular region and oversee the feasibility of the proposals.

While a policy statement on LNG has been expected for some time it is likely that the government would leave these matters to the market to decide. One reason certainly is that the subsidies are now being phased out and in about five years' time this concern may not be important. As mentioned earlier, producers of gas from NELP blocks, including NOCs, would be free to market the gas. LNG importers would likewise be free to market gas at negotiated prices. If the government wanted to regulate these prices, powers would have to be acquired under a statute and the government has made no moves in that direction.

There are reports that an inter-ministerial committee of secretaries would be formed to regulate the LNG industry pending the appointment of a regulator. The union budget of February 2001 has rationalised the import duty structure for LNG removing the disparities that were earlier there between the power and other importing sectors. However, the eagerly awaited announcement granting 'infrastructure industry' status to the LNG industry did not come through. While appreciating the need for an early announcement of the LNG policy, one must note with satisfaction that the government has resisted demands for a tight fisted regulation of the industry. Although the policy is delayed, the government seems to be thinking along the right lines in allowing the market a greater role in regulating the number and size of the projects.

One important factor that would influence the choice between LNG and the alternatives of naphtha and fuel oil is the customs duty. Indications are that the country would have an excess of both naphtha and fuel oil in future and the government may well protect the domestic industry with high import duties. LNG could therefore continue to have a lower duty than fuel oil/naphtha.

LNG shipping policy

An aspect of the LNG policy that has attracted attention is the LNG shipping policy. The policy is yet to be officially announced but the broad parameters are known. LNG transporters are to have at least 26% equity held by an Indian shipping company throughout the period of the contract. Further, the Indian company has to be associated in operating the ships so that there is effective transfer of know how in manning and operation of these vessels by Indian personnel. The Indian partners in the shipping consortium should together hold 50% equity. The policy allows only fob imports of LNG at present. This would be reviewed after seven years. To facilitate conversion of LNG vessels to the Indian flag, Indian LNG shippers may get tax exemptions for specified periods. At present only the Shipping Corporation of India has joined a consortium for shipping LNG.

These measures may be criticised on the ground that they put an additional cost on the LNG importer but over the long term, may bring the transport costs down. The policy also seeks to encourage major shipyards in India to develop repairing facilities for LNG carriers.

Regulating the transmission and distribution of natural gas

Study by National Economic Research Associates (NERA) of UK

The natural gas industry in India is in transition as it attempts to move from a highly centralised, government-controlled business to one that relies increasingly upon reduced regulation and a more market-responsive pricing climate to encourage foreign and private sector investment. In order to examine the options for a regulatory framework for the gas industry, the government commissioned a study by the NERA. A summary of the recommendations is given below.

- Exclusivity to develop new transmission lines, and extensions and additions to new lines, should not be granted to GAIL or any other entity, in order that there can be some element of competition in the provision of new facilities. However, the regulatory framework should be established in such a way as to ensure that the orderly development of the industry can be ensured.
- Gas transportation should be provided on the basis of "unbundled" service, that is separate provision of transportation and gas supply services.
- The framework of regulation should be established such that transmission services be provided on the basis of contract carriage. This ensures efficiency in that capacity is constructed where there are users prepared to pay for it. Individual pipeline operators (transmitters) have only limited responsibility for system development.
- The regulatory body be empowered to ensure that effective transportation contracts are put in place for all existing and new users of the existing facilities.
- Regulatory powers be provided with regard to the contract terms on which new transmission facilities are developed, this being a condition for regulatory approval of new transmission pipelines.

- Regulatory powers be provided with regard to the interconnection of new and existing lines.

Distribution systems should be regarded as separately regulated entities, and subject to distinct regulatory provisions:

- The regulation should provide for exclusive franchises for distribution, this being the only sensible option in the Indian context.
- Cross-ownership between distribution, transmission, and bulk supply be permitted, but that there are regulatory provisions concerned with the transparent separation of accounts between the different businesses.
- Bulk transmitters of gas should also be permitted to sell gas subject to appropriate regulatory safeguards. In particular, this would mean full and transparent separation of accounts for the transmission and trading activities.
- In the long term there is no need to regulate the price of bulk gas supplies. Interim measures, such as regulated bulk supply contracts for existing supplies will be necessary to ease the transition to full price liberalisation.

Gas Act

The government has so far controlled gas production and marketing by virtue of being the owner of ONGC and GAIL. With the entry of private parties, government would need to acquire statutory powers. Ever since the submission of the NERA report, there has been an expectation of a Gas Act installing an independent regulator. Such regulators are already in place for the electricity and the telecom sectors. It seems however that the government is not yet prepared to have an independent regulator in place and that regulation by government would continue for sometime. The existing set up is dominated by public sector undertakings who are happy with direct regulation by the government and there is no pressure from any quarter for an early passing of the Act. The only possible pressure could come from the potential LNG suppliers who may need to have a transparent transmission system in place in order to secure finance for their projects. However, there is no evidence of any such pressure being brought on the government.

While the central government dithered, unable to decide on the merits of a Gas Act, Gujarat, (where 4 LNG import terminals are planned) has gone ahead and enacted its own gas law. Maharashtra, another state where two LNG terminals have been proposed, is likely to follow suit. Is there as possibility of conflicts between state and central laws creating difficulty for the industry? The differences over the Gujarat Act has been reported in the press. Some aspects of the Act are still under discussion between the two governments and indications are that these would be settled amicably.

Pipeline tariffs and third party access

The transportation charges along the HBJ pipeline is decided by the government. It was first fixed in 1987 and subsequently revised in 1997. GAIL was allowed a 12% post-tax return on equity. The charges along the other pipelines operated by GAIL were determined by GAIL based on the same principle. Consumers along the 2300 km long HBJ pipeline are charged the same tariff irrespective of location. This 'postage stamp' tariff is likely to continue; a distance related tariff and the need to feed in LNG would make the tail-enders non-viable. Would tariff be equated over new pipelines? This question would be politically sensitive with different states favouring different solutions. However, with the entry of private operators in gas production and transportation, a distance related tariff is likely to emerge for new pipelines.

An important consideration for the LNG importer is whether access would be available into the existing pipeline network of GAIL. The HBJ pipeline, for instance, would open up north-western India to LNG terminals in Gujarat. GAIL's pipeline in Andhra Pradesh would be crucial for the proposed LNG terminal at Kakinada. Such questions ought to be decided quickly, as capacity upgradation of these pipelines is under study. Unfortunately, there is no clarity on this issue. LNG importers would have to negotiate the terms of access with GAIL. Wherever feasible, they may try to rope in GAIL as a partner in the LNG project. As the gas grid in the country is not highly developed, there is a need to bring in investment to create additional pipeline capacity. The government or the regulator, when appointed will need to decide the issue of third party access keeping this requirement in mind.

Gas allocations to consumers

Gas prices have been fixed by the government since 1987. The government also makes gas allocations to individual consumers. The regime of allocation was based on the premise that gas was in short supply and that the government was the best judge of how to use the gas. Following the recommendations of the Varadharajan committee (1987), these allocations were based on the imputed values of gas use in the various sectors, subject to preference for the power and the fertiliser sectors. The sectoral pattern of gas use would, however, not be widely different if allocations were left to the market.

The first departure from this system of allocation was made in the cases of private producers of gas under production sharing contracts. These developers were free to choose their customers and sell gas to them at negotiated prices.

It may be noted that gas allocations were made by the government as shareholders in the public sector gas producers and marketers. Since this was not done under a statutory power, private sector gas producers or importers of LNG are outside the purview of these allocation orders. As the NELP places the NOCs on a level playing field with private NOCs would be free to market gas produced from fields acquired under the NELP. These developments point towards the abolition of the allocation regime and its replacement by market forces.

Gas pricing

The price of natural gas has been fixed by the Central Government since 1987. In 1987, the price was $0.86/MMBtu ($1= Rs 46) for gas at landfall points and a flat $1.38/MMBtu for gas along the HBJ line. The gas price was much lower than the prices of alternative fuels and the government felt the need to bring the price to the consumer in line with these prices.

Linkage to long run marginal costs

The Kelkar Committee was appointed in 1990 to recommend revisions in the gas prices. The committee recommended that the price payable to the producers be fixed at the long run marginal cost of production estimated at $0.92/MMBtu. The consumer price was to be increased annually to reach $1.13/MMbtu, which was near enough to the prevailing fuel oil price. The difference between the consumer price and the producer price was credited to the Gas Pool Account - an account set up to compensate ONGC and OIL for the concessional price of gas in the North East.

In 1996 the Sankar Committee was established to review the above rates, with some consideration given to the impending need for gas imports and the effects of import parity pricing. The committee decided that import parity pricing would be too steep a transition. The committee left intact the principles of fixing the producer price and the consumer price earlier recommended by Kelkar. The prices were however revised upward based on fresh estimation of the costs.

Linkage to fuel oil prices

Having considered these recommendations, in October 1997 the government instituted a new series of gas prices, valid through to March 31, 2000. The consumer price of gas at landfall points were linked to the price of a basket of fuel oils as shown in the Table 3.2.

Table 3.2 Natural Gas Pricing against a basket of Fuel Oils

	Percentage of LSHS/FO price	
Year	General Price	Concessional Price for the NE States
1997-98	55%	35%
1998-99	65%	40%
1999-2000	75%	45%

The price is determined and notified by GAIL with the approval of the Ministry for every quarter depending upon the average price of the following basket of fuel oils (with equal weights to each type) based on figures obtained from Platt's Oilgram for the previous quarter: FOB, Med basis, Italy (1% Sulphur); CIF NWE basis, ARA (1% Sulphur); Singapore, FOB, HSFO 180 cst (3.9% Sulphur); Arabian Gulf, FOB, HSFO 180 cst (3.9% Sulphur).

The gas price, although it continued to be an administered price, was brought close to market prices. A major device introduced to protect the producers as well as the consumers was a floor price of $1.32/MMBtu and a ceiling price of $1.76/MMBtu. The price has now reached the ceiling and is being reviewed with a view to introducing 100% fuel oil parity prices. The above gas prices are linked to the calorific value of 10,000 kCal/cu. Metre. The transportation charges on the HBJ pipeline were revised in 1997 to $0.71/MMbtu. A linkage was also provided to inflation. The transportation charge on the HBJ pipeline provides GAIL a 12% post-tax return on net worth. The transportation charges on other pipelines is fixed by GAIL on the same principle.

Gas Sales by ONGC/OIL to GAIL

The above prices are applicable to gas sold by ONGC or OIL to GAIL and to sales by GAIL to consumers/distribution companies. ONGC/OIL/GAIL and joint venture operations are permitted to sell gas from marginal isolated fields to be developed in future, at market driven prices.

Gas sales by private upstream companies

To GAIL. These are negotiated between the government and the private operators and included in the production sharing contracts. So far these prices have been full fuel oil parity prices but the fuel oils basket could differ from one case to another.

Direct to end-users. These are freely negotiated and are mostly linked to prices of alternative fuels. Transportation charges are also negotiated.

Gas Sales by Distribution Companies to end-users. These are negotiated prices linked to alternative fuels.

Taxes and duties

In addition to the price as fixed above, royalty, taxes, duties and other statutory levies on the production and sale of natural gas is payable by the consumer. The royalty on gas as fixed under the Oilfields Development Act is 10% of the wellhead price. For gas sold by ONGC, this is now $0.18/MMbtu, one-tenth of the ceiling price of $1.80/MMbtu. For privately operated fields, the royalty is fixed on the negotiated wellhead prices. There is no cess on natural gas (unlike crude oil) although a cess could be levied under the law. There is no excise duty on natural gas or on crude oil as these are minerals although excise duty is charged on petroleum products. A sales tax is leviable at state rates if the sale is within the state or at the central rate of 4% for inter-state sales. The state sales tax rates vary from one state to another, ranging from zero to 22%.

A typical price build up for gas produced in a state and sold within the state would be as below:

	$/MMbtu
Gas price	1.80
Royalty	0.18
Transportation charge	0.43
Sales Tax (20%)	0.48
Total	2.89

It is to be noted that GAIL does not make a margin on merchant sales; it is allowed a return only on its investment in the pipeline.

In addition, there would be a customs duty to be paid on imported gas/LNG. This duty is now 5%. A countervailing duty of 16% was levied till the year 2000 on LNG except when used for power generation. This has now been removed so that the duty is now the same for all consumers. The gas industry has been asking for 'infrastructure' status, with a consequent reduction in the customs duty to be paid on components imported for pipelines and LNG receiving terminals. The concession, if granted, could make a difference of around 7-8 cents/ MMbtu in the regasification cost. However, there is no guarantee that the benefit would be passed on to the consumer. The government has not yet agreed and is not likely to agree.

Contractual arrangements for sale of gas

There is no contract as yet between ONGC and GAIL regarding gas supplied by the former to the latter. This has not given rise to major problems as both are public sector undertakings. For supplies to its consumers, GAIL has evolved a standard contract to which case-specific small variations can be made. The major points covered in such contracts are:

- *Period of contract*: The period is between 10 and 15 years from the date of commencement of supply.
- *Activity milestones for new customers*: The contract spells out the dates of completion of major activities for new plants like purchase of land, ordering of equipment, commencement of construction, completion of construction, etc. The contract requires all purchasers to lodge with GAIL a refundable cash deposit and a bank guarantee (equivalent to about three times the cash deposit). GAIL is required to pay interest on the cash deposit. The contract also stipulates that GAIL has the right to forfeit 25% of the bank guarantee for delay in completion of any of the stipulated major activities in a new plant beyond three months of the milestone schedule. The right of GAIL to cancel the contract for further delays in construction activities is also incorporated in the contract.
- *Manner of delivery of gas*: The inlet pressures, location of the Gas Metering Station, its installation and maintenance by the seller at the consumer's cost and provision of a check metering station by the consumer, are provided in the contract. Besides, frequency and method of calibration of metering unit are specified.
- *Quantity of gas*: The progressive schedule of delivery is indicated in the contract in terms of daily quantity. However, prior to each contract year the customer is required to indicate a forecast of gas requirement. The customer guarantees a minimum off-take of around 80% of the contracted quantity and payments being made up to this 80% level even when the off-takes are lower (take or pay).
- *Specification of gas*: The quality of gas to be supplied and the method to be followed for gas sampling is annotated. Typical limits of composition of the gas at the delivery point are indicated.
- *Price of gas*: This is as decided by the GOI in its price notification that is issued periodically. In addition transportation charges, royalty, taxes, duties and other statutory levies of the Central/State Government or any other local bodies are borne by the buyer.
- *Transport cost*: This is either a fixed amount as for delivery ex-HBJ pipeline or according to a formula, where a new gas line is laid for making supplies of gas available to a consumer. In respect of existing customers outside the HBJ

pipeline, the transport charges as earlier agreed mutually between the supplier and consumer will continue. However, for future the new formula will be relevant. This formula covers annual depreciation of pipeline cost, reasonable return on capital cost of the pipeline and its operation and maintenance costs. The transport cost is subject to escalation at 3% per annum.

- *Billing and payment terms*: Invoices are submitted fortnightly and customers are to pay within 3 working days of presentation of an invoice. The customer has to open and maintain an irrevocable Letter of Credit with a bank notified by the seller, covering a value of fifteen days supply of gas at maximum contracted quantity and the monthly transportation charge. If, for any reason, payment is delayed or any disallowance made from the invoice, the seller may present the invoice for the full amount or for the amount not paid, as the case may be, to the bank against the Letter of Credit and draw the amount. For supplies to continue, the customer has to reinstate the full amount of L/C.
- *Arbitration*: This is generally guided by the provisions of Indian Arbitration Act. Besides, other Indian Laws relating to contract, etc. are fully applicable.

GAIL's contracts with consumers have been criticised as being one-sided. While GAIL is protected by take-or-pay provisions, there is no penalty on GAIL for short-supply.

Issues in gas contracts

Some of the important points in respect of these contracts between different parties are listed below. First, different prices prevail at different locations depending on the transportation cost and sales tax, but no distinction is made currently between different categories of consumers in the same location with reference to the opportunity value of gas they use. Secondly, supplies of gas to all categories are non-interruptible, except for those delivered to "fall-back" customers. Currently to avoid under-utilisation of available gas, allocations are made in excess of the availability. This requires rationing of gas and the use of alternative fuels. While dual-fuel arrangements were earlier made only as exceptions, the Government now insists on dual-fuel arrangements for all customers. Thirdly, GAIL today discharges the role of both a transporter and a merchant. In the few cases where ONGC and OIL sell gas direct to consumers, they also provide 'bundled' services.

Pricing of gas from LNG

The long run marginal cost of producing gas by ONGC has been estimated at $1.1/MMbtu. The cost of production from medium sized fields operated by OIL or private operators would be slightly higher. The cost of gas likely to be found in the NELP blocks would vary, depending on the size of the gas discoveries. Andhra Pradesh is the only place where large discoveries are expected and gas-to-gas competition may drive the gas price down. Elsewhere, gas should be saleable at replacement prices of alternative fuels. For the power sector, the alternative fuel is coal, domestic or imported. In the production of urea, the competition is with imported urea. In industries, the alternatives are coal, fuel oil and LPG. The replacement prices or imputed values are computed for different consumers at various locations elsewhere in this report. The imputed values will be the highest for power, urea and the glass and ceramic units as also for the domestic sector where gas will replace LPG.

At present, GAIL is selling gas at fuel oil linked prices. These prices would soon rise to full fuel oil parity. A proposal to this effect is pending for approval. With the present high prices of fuel oil, the gas price which is now capped at $1.76/MMbtu would jump to around $3.6/MMbtu. The price along the HBJ would then be $4.28/MMbtu. The consumers are resisting this steep increase. The steel industry, an important gas consumer now reeling under recession will be hit badly. The finance ministry is unhappy because the fertiliser subsidy will go up sharply.

Even after the price revision goes through, the price to many consumers would be below the imputed value. In the case of LNG it is clear that the price to the consumer would be the replacement value as otherwise LNG would not be saleable. The same would be true of gas found in NELP blocks or CBM blocks and sold through negotiations. The question remains if GAIL would be allowed at that time to charge market prices in respect of domestic gas also? This is quite likely. As seen above, the gas price would be fairly close to the import parity level once the price cap is removed. Besides, it would be difficult to have different prices for the same fuel, especially as they would be physically mixed up in most cases.

A number of naphtha based power plants were commissioned in the country over the last two years. All of these ran into trouble on account of soaring naphtha prices, including the Enron project in Maharashtra which received a lot of publicity. Many of these units were restricted to the minimum guaranteed offtake of power. This experience has important implications for LNG. The electricity regulator who has to approve the procurement of power by utilities would approve an LNG based power plant only if satisfied that it would cost less than others. Such comparisons would assume a price band for crude oil, something like $20 to 25/bbl. Although there are many locations where LNG would be a competitive option at these prices, the project may not be able to deliver power if crude oil prices go up to $30/bbl or more. The regulators would probably require price ceilings while approving LNG based projects. This would be true of fluctuations in the rupee-dollar parity also. Accordingly, the dollar denominated portion of the gas price would need to be kept at the minimum possible level.

Exploration for coal bed methane

India is endowed with rich deposits of coal and lignite. The bulk of the coal resources of about 212 billion tonnes is in the Gondwana basins of peninsular India. Large deposits of lignite are known to occur in Tamil Nadu, Gujarat and Rajasthan. The proven reserves of coal is estimated at 82 billion tonnes.

These coal and lignite seams contain varying amounts of methane depending on the rank of the carbonaceous matter, the depth of burial and the geotectonic setting of the basins. The commercial production of such methane, better known as Coal Bed Methane (CBM) is a proven technology and has added to the natural gas production of some countries.

The government wishes to involve both the public and the private sectors in developing these resources. The exploration and development is proposed to be spread over four phases:

Phase I	:	Exploration	3 years
Phase II A	:	Pilot Assessment	3 years
Phase II B	:	Market Confirmation	2 years
Phase III	:	Development	5 years
Phase IV	:	Production	25 years

The important parameters which have been kept in view in delineating the exploration blocks are as below:

- Occurrence of high rank coals
- Development of thick coal seams.
- High gas content of the seam.
- Presence of well developed cleats/fractures in the seams to induce higher permeability.
- Deep burial of the seams beyond 600 m depth.
- Evidence of emission of methane gas in adjoining coal mines/boreholes.

Keeping the above parameters in view, seven blocks in the Gondwana basins have been delineated and offered in the first bidding round for exploration and exploitation of CBM. These blocks are located in Raniganj (West Bengal), Bokaro and North Karanpura (Jharkhand), Sohagpur and Satpura (Madhya Pradesh) and one in Barmer (Rajasthan). Preliminary estimates suggest that these blocks could contain about 9 TCF (262 BCM) of methane gas.

The fiscal & contractual terms are as below:

- There will be no Government participation in the project.
- Allotment of blocks would be through a system of global bidding.
- Exploration and development will be under concessions and not under PSCs.
- No signature bonus.
- No Customs duty.
- The project will enjoy the benefits of an Infrastructure status which provides for a 7 year tax holiday from the date of commencement of production.
- Base rate of 10% ad-valorem royalty payable to the State Governments.
- Additional production level payments are biddable. Payments on sliding scale for every 0.5 MMSCMD of incremental gas production after reaching the production of 1.0 MMSCMD.
- Nominal commercial bonus of S0.3 million on declaration of commercial assessment.
- Liberal depreciation provisions.
- Contribution to site restoration fund tax deductible.
- Model contract to be put in place.
- New Petroleum Tax Guide to facilitate investors
- Freedom to sell gas in the domestic market.
- Provision for 100% cost recovery.

Road shows for the first bidding round have been in held in Delhi and the USA in May, 2001.

Although the decision to explore for CBM was taken by the government as far back as 1996, exploration of CBM blocks was delayed for a long time as the ministries of coal and petroleum could not agree on a number of methodological issues. Later, differences between the center and the states held up the bidding round. At least a partial resolution of these issues has now been possible and one can look forward to some long term results in this field.

Petroleum

At the time of independence, the petroleum industry in India was run by multinational companies, Burmah Shell, ESSO and Caltex. The ONGC and the Indian Oil Corporation were formed in the late fifties. In the seventies, the assets of the MNCs were acquired by government on a negotiated sale basis. By the time the economic reforms were launched in the nineties, the industry was dominated by public sector companies engaged in exploration, refining, marketing and distribution.

The upstream sector was the first to be opened up to the private sector. As mentioned earlier, exploration bidding rounds picked up momentum in the nineties. Next, the private sector was allowed into refining. This has proved to be the most successful initiative so far resulting in 27 MMTPA of additional capacity put up by Reliance at Jamnagar with other proposals in the pipeline.

Administrated pricing mechanism

Opening up of the lucrative marketing sector has been scheduled for April 2002. In the original notification, the condition for entry was an investment of Rs 20 billion in refining or the production of 3 MMTPA of oil. An official committee has now recommended that the investment would be allowed in refining, pipelines or terminals.

Opening up the petroleum industry called for major changes in regulation. The existing regulations were built around the Administered Pricing Mechanism (APM) introduced in 1976. The APM works as follows:

- The cost of crude included in the selling price is computed at weighted average price of indigenous and imported crude oil.
- Standards are laid down for each refinery in respect of throughput level, product pattern, fuel and loss, operating cost and capital employed.
- The total cost of production and the refiners' profit are estimated based on the above standards. The refineries are allowed a 12% post-tax return on net worth and actual interest cost on the borrowings included in the capital employed (Net Fixed Assets plus Normative Working Capital). A set of indices is used for allocating the costs over products.
- Ex-refinery price, which is the price at which products are sold to marketing companies, is uniform at all the refineries. The ex-refinery price is based on the weighted average cost of products of all refineries.
- The marketing costs and profits (referred to as marketing margins) are also estimated taking into account the norms fixed for marketing operations. As in the case of refineries, the marketing companies are allowed an after tax return of 12% on net worth and reimbursement of borrowing cost. The marketing margins are averaged out to compute industry margins for inclusion in the selling price.
- The selling price of products to the consumer includes, in addition to industry average costs and profits, notional railway freight (from the most economic source irrespective of the actual supply point), retailing cost wherever applicable, various surcharges and governmental levies.

- Irrespective of the company marketing the product and the location from which the product is actually sourced, prices of products at a location are maintained at an uniform level.
- Products like SKO, LPG (Domestic), Naphtha, LSHS and FO for fertiliser units, and Bitumen are subsidised. The cost of the subsidy is borne by products like MS, ATF (Domestic Airlines), LPG (Bulk), Naphtha, FO, LSHS (for use other than fertilisers).
- In order to maintain this system, OCC operates a number of pool accounts. Companies either pay to or recover from these accounts, in order to retain their margins. Rewards and penalties are in-built in the system.

This mechanism has served the following objectives:

- To ensure availability of certain products at subsidized rates to the economically weaker sections of the society and for priority sectors like fertilizers. This is achieved through a system of cross subsidization of products,
- To ensure stable prices so that the domestic market is insulated from the volatility of prices in the international market,
- To regulate returns to the oil companies at reasonable levels consistent with efficiency of operations, to generate sufficient resources for encouraging growth of infrastructure facilities,
- To minimize the cross haulage of products by making available products at a uniform price ex-all refineries, and
- To achieve social objectives such as demand management.

Phased reform program

In spite of these features, the system proved unworkable for several reasons. The cost-plus method of pricing did not provide incentives for efficiency. The government was reluctant to increase product prices in step with rising costs and the dues to the oil companies mounted so much as to affect their financial health. The government accordingly favoured the introduction of market prices. An expert group called the R-Group was formed to examine ways of bringing in the change. The government accepted the recommendations of the group and announced a phased reform program starting April 1, 1998. The important features of the program were:

- Fixed time frame for implementation (1998-2002)
- International price for domestic crude oil
- Retention pricing for refineries abolished
- Ex-refinery prices of controlled products to be fixed by OCC
- Adjusted import parity for existing refineries

- Tariff adjusted import parity for new refineries (set up after 1.4.98)
- Decontrolled products - refineries free to set own prices i.e. naphtha, fuel oil etc.
- Rationalisation of customs duty on crude & products to provide tariff protection to refineries.
- Marketing rights of transportation fuels to new players subject to conditionalities.
- Phasing out of subsidies. Subsidies beyond 2002 to be funded from general budget.
- Regulatory body to be established.

Off and on there have been press reports on the scheduled price decontrol getting delayed or being advanced. The large increase in the crude oil price in 1999-2000 fueled speculations that the decontrol would be postponed. As of today it seems the timetable would be adhered to. This has been reiterated by the Petroleum Minister in his recent statements and by the Finance Minister in his budget speech.

Regulation

The government commissioned a study by TERI in 1997 on the possible models for regulation in this sector. The report brought out the need to combine a free market with the imperatives of servicing remote areas and the ways of combating cartelisation in the industry. A more recent report by TERI has looked into the option of an interim arrangement of regulation by the ministry pending the appointment of an independent regulator. The report is under study in the government. One of the basic questions that the government is grappling with is whether there should be one regulator for the oil and gas industry or if two or even three regulators would be required. At present it looks as though a single regulator would be installed for the gas and the downstream petroleum sectors while another regulates the upstream sector. The appointment of independent regulators would be preceded by an interim arrangement where a departmental official may be appointed the regulator.

Coal

Growth of the industry

Coal is the most abundant fossil fuel in India. It accounts for 56% of the country's primary energy supply and about the same percentage of the power generation capacity. The country's industrial heritage was built upon indigenous coal. The coal available in India is primarily low grade non-coking coal. This coal is characterised by a high ash content (upwards of 40%), low calorific content and very low sulphur content.

The coal industry in India was largely in the hands of the private sector until the end of 1971. There was a large number of operators of varying sizes. National Coal Development Corporation (NCDC) and Singareni Coal Company (SCCL) were setup in the public sector in the fifties. SCCL was formed in 1950 as a joint venture with the state of Andhra Pradesh to mine coal in southern India. NCDC was founded in 1956 primarily to locate and mine coal from outlying coalfields in central and western India. NCDC took the lead in exploiting shallow deposits through mechanised open cast mining.

The coal industry was nationalised in two stages - coking coal mines were taken over in October 1971 and other coal mines in January 1973. Subsequently, the industry was reorganised with Coal India as the holding company and seven coal producing subsidiaries, operating mines in different regions.

The industry was nationalised, apart from other considerations, with a view to ensure that the production of coal should be properly planned to meet the increasing requirements in the industrial development of the country. It was expected that nationalisation of the coal industry would also ensure fair and equitable distribution of coal to meet the essential needs of users, both in the core and non-core sectors. To ensure sustained and planned development of all facets of the coal industry, a massive investment to the tune of about Rs. 180 billion ($ 3900 million) has been made in opening up of new mines, re-organisation of existing mines and development of associated infrastructure.

Coal production has registered an annual growth rate of about 4.8 % since nationalisation, increasing from a level of 73 MMT in 1970/71 to 300 MMT in 1999/2000. In the post-nationalisation period, the major thrust was on the development of new outlying coalfields like Rajmahal, North Karanpura (Bihar), Singrauli, Korba (MP), Ib Valley and Talcher (Orissa). These coalfields contributed 43% of the total coal production in 1994/95. Their contribution is projected to be 60 % by the year 2010/11. Consequent upon the development of new coalfields in outlying areas, a large number of pithead super thermal power stations have come up. This has helped in reducing the load on railways as most of these pithead power stations transport their coal by captive modes such as merry-go-round and cross country belt systems.

Till the end of the Seventh Five-year Plan (1990) the coal sector depended fully on the budgetary support provided by the government for new developments including exploration. From the Eighth Plan onwards, the government has phased out this support. Due to this reason, investments in new projects has been low in the last few years. This is likely to increase the gap between production and demand in the future.

Coal pricing

Since nationalisation, coal prices have been regulated and revised several times on the suggestions of Committees and Working Groups set up by the Government.

In the pre-nationalisation period, coal prices remained fairly low. The prices increased at a rate of 3.5 % during the 1950s and 5.6 % during the 1960s. The post-nationalisation period witnessed a sharp rise in prices, registering an annual rate of increase of 12.8 percent during 1970/80 and 9.7 percent during 1980/95.

In general, all the committees advocated that the pithead price of coal should be related to the industry-wide average cost of production with suitable allowance made for cost increases. The Bureau of Industrial Costs and Prices (BICP) has been working out normative costs based on normative rather than actual levels of efficiency and had been recommending a weighted average price on the basis of the estimates from different categories of mines. However, the coal industry has not been able to achieve these normative levels of efficiency or the projected mix of production of different grades of coal. The industry was therefore not fully compensated for their costs and the financial health of the coal companies deteriorated over time.

In 1996, the government deregulated the prices of A, B & C grades of non-coking coal and all grades of coking coal. In February 1997, the government decided to deregulate the prices of 'D' grade non-coking coal, hard coke and soft coke. Finally, the prices of E, F & G grades of coal were decontrolled on 1st January 2000.

Since the capacity in eastern sector is larger than the demand, coal moves over long distances to the north and west. The freight rate is more than 50% of the delivered cost of coal at 1000 km. With coal prices decontrolled, consumers should be able to strike deals with nearby fields and the movement of coal is expected to reduce.

The government protects the domestic coal industry with a customs duty. In the case of non-coking coal, the present rate of custom duty is 25 % with a surcharge depending on the ash content. The import of coal is however increasing and around 7.5 million tonnes of non-coking coal were imported last year.

Policy reform

In a major policy initiative, captive coal mining has been allowed to both private sector and public sector companies including the state level power utilities for generation of power, production of iron and steel, cement and for washing of coal.

Foreign investment in Indian companies taking up coal mining activity for captive consumption for approved end-uses has been allowed. The extent of equity participation is decided on a case to case basis.

82 mining blocks have been identified for captive mining with an estimated coal reserve of 20 billion tons and annual production potential of 150 million tons. Of these, 23 blocks have already been allotted to power producers and 4 to the steel industry. Captive mining is yet to really take off. Lack of facilities such as power and railway lines near the allotted blocks as well as the difficulties in the power sector have been the important factors.

Private investment is also being invited in clean coal technologies like Integrated Gassification Combined Cycle (IGCC), Pressurised Fluidised Bed Combustion (PFBC), Coal Beneficiation and Slurry Combustion and In-situ Coal Gassification. However, the results have not been very encouraging till date. For coal sector reforms to take off, it may be necessary to appoint an independent regulatory body for this sector. The government has recently completed studies in this regard. The report is under consideration in the government.

Coal sector reforms have not received the publicity that the oil or power sectors have. Nevertheless, very important changes have been introduced. Major changes are still required in order to increase the production capacity and to improve the quality of the coal. As most of the coal is used for power generation, further reforms in the coal sector would depend on how the power sector develops. Coal is also the most important competitor for gas/LNG for power generation and the development of the gas industry in turn depends on progress of coal sector reforms.

Electricity

Like the petroleum industry, the power sector has been characterised by cross-subsidies. In the oil industry these cross-subsidies are between products; in the power sector these are between different kinds of consumers. Supplies to the agricultural and residential sectors are subsidised by overcharging industrial consumers. As the limits of cross-subsidy were reached, net subsidies from the government were required. These were mostly inadequate and often delayed. The result was that the electricity boards in the states suffered losses and were in no position to make the investments necessary to meet the rising demand for power.

Minimum National Action Plan

Projections made at the time of formulating the ninth five year plan pointed to the need to add 10,000 MW every year. There was a clear need to rope in the private sector in power generation, transmission and distribution and the institutional set up had to be changed to make this possible. An important landmark in this process was the meeting between the Prime Minister and the Chief Ministers of the states in December 1996. The main features of the Minimum National Action Plan adopted in the meeting are listed below.

- Central Government will set up a Central Electricity Regulatory Commission (CERC).
- Each State and Union Territory will set up a State Electricity Regulatory Commission (SERC).
- Central Government will issue transparent guidelines and delegate more powers for environmental clearance to the state agencies.
- States to allow maximum autonomy to the SEBs and they will be restructured and run on professional lines.
- Rationalisation of retail tariffs to be carried out over time. No sector to pay less than 50% of the cost of supply. Agricultural tariff was to be at least Rs. 0.50 per kWh and to be brought to 50% of the average cost of supply in not more than three years.
- The supply to the agricultural consumers is to be metered.
- Steps to be initiated by the states to introduce participation of private sector in electricity distribution.
- SEBs to improve their professional standards and project management practices.
- Central Government to finalise the linkages of allocation of liquid fuels in consultation with the State Governments.
- States to evolve transparent policies for purchasing and wheeling of power for captive and cogeneration plants.
- Steps to be initiated to improve the physical performance like PLF of the plants, metering etc.
- High priority to be accorded to the hydro projects and the Central Government is to evolve a policy framework for the same.

The important initiatives taken in accordance of the above decisions are discussed below.

Central Electricity Regulatory Commission

The Electricity Regulatory Commission Act, 1998 came into force in July 1998. This Act provides for the establishment of the Central Electricity Regulatory Commission to regulate the tariff of the generating companies owned by the central government, to regulate the tariff of other generating companies selling electricity to two or more states and to regulate inter-state transmission of electricity. The Act also provides for the establishment of state level regulatory commissions.

The Central Electricity Regulatory Commission was constituted as a statutory body in July 1998 with a Chairperson and three members. The functions of the CERC include the following:

- To regulate the tariff of generating companies owned or controlled by the Central Government.
- To regulate the tariff of generating companies, other than those owned or controlled by the Central Government, if such generating companies enter into or otherwise have a composite scheme for generation and sale of electricity in more than one State;
- To regulate the inter-State transmission of energy including tariff of the transmission utilities;
- To promote competition, efficiency and economy in the activities of the electricity industry;
- To aid and advise the Central Government in the formulation of tariff policy which shall be:
    - Fair to the consumers;
    - Facilitate mobilisation of adequate resources for the power sector;
    - To associate with the environmental regulatory agencies to develop appropriate policies and procedures for environmental regulation of the power sector;
    - To frame guidelines in matters relating to electricity tariff;
    - To arbitrate or adjudicate upon disputes involving generating companies or transmission utilities in regard to matters connected with clause (a) to (c) above;
    - To aid and advise the Central Government on any other matter referred to the Central Commission by that Government.

The transmission bill

The Transmission Bill facilitating the entry of private sector in the transmission business was passed by the Parliament in 1998. The bill is aimed only at facilitating private investment. The Government will continue to retain control over power transmission through central grids or SEBs. The bill will allow private firms to invest in facilities for transmission and to operate and maintain these facilities.

Mega power projects policy

In view of the slippage in setting up additional generation capacity in the Ninth Plan, the government has announced a policy package for mega power projects to be developed in the country. To qualify for incentives under this scheme, a project has to satisfy the following three conditions:

- The capacity should be more than 1000 MW in case of thermal power projects and 500 MW in case of hydroelectric power projects.
- The project should sell power to more than one state.
- The tariff should be approved for Central Electricity Regulatory Commission.

The policy will be applicable to government-owned as well as privately owned projects. The government expects to add approximately 25,000 MW of capacity through such projects, of which the private sector is expected to contribute about 40%.

The incentives include a complete waiver of the customs duty on import of equipment, which is currently more than 20 percent. It also provides a 15% price preference and deemed export benefit for domestic bidders.

Further, it is proposed that the recently formed Power Trading Corporation (PTC), with equity participation of NTPC, NHPC, PGCIL and financial institutions such as PFC will act as an intermediary between the private developers of mega projects and the State Electricity Boards. This arrangement will work as a de facto counter-guarantee. However, the Central Government has imposed conditions which have to be satisfied before PTC can sell power to a State Electricity Board. The concerned State must have established a State Electricity Regulatory Commission and should have involved the private sector in the electricity distribution business.

Status of reforms in the states

Several states have set up Regulatory Commissions. Some have gone further and split up the electricity boards. Only one state, Orissa, has privatised distribution. The regulators in Orissa, UP, Haryana, Maharashtra, Gujarat, Andhra Pradesh and Karnataka have passed tariff orders. These orders reveal a trend towards removal of cross-subsidies as the tariff increases have been more pronounced for the domestic and agricultural sectors. However, the Karnataka, Maharashtra and Gujarat governments have not allowed the tariff increases for the farmers. The financial position of the electricity boards remain bad and many of them are unable to provide escrow cover to IPPs.

The situation has been reviewed by the Prime Minister in a meeting with the Chief Ministers on March 3, 2001. It was noted in the meeting that capacity addition in the ninth plan (1997-2002) would be 21000 MW, about half the target. The need for additional capacity by 2012 was 100,000 MW. The losses in high voltage transmission amounted to 12 to 13% and in distribution from 40 to 45%. Tariff rationalisation, reduction in T&D losses, energy audits, a time-bound program for 100% metering of supplies were among the important measures suggested.

The pace of changes in the sector has been slow. This is understandable in view of the dimension of the problem being addressed. It is however true that the regulatory commissions have been able to put the reforms agenda firmly on the table. The success of the reforms would determine the extent to which the electricity boards would, in the long run, be able to support additional generation capacity based on LNG or any other fuel. In the short run, the state governments would have to bail out the utilities.

The case of the Dabhol Power Project of Enron in Maharashtra has drawn much flak recently. The first unit of this project (715 MW) was commissioned in 2000 on naphtha. The proximate cause of the high power prices, at times exceeding 15 cents a unit, was the high price of naphtha. A close look by an expert committee appointed by the government has however shown a number of ways in which the power cost could be brought down. For instance, the power project need not bear the entire cost of LNG regasification when it would use only a part of the LNG. Both sides have reportedly agreed to a renegotiation of the power purchase agreement but some hard bargaining can be expected. More details are provided in Chapter 7.

When a project suffers such a setback, the future of reforms becomes suspect. It may be remembered, however, that this project belongs to the period immediately following the opening up of the power sector. Since then the selection of IPPs through competitive bidding has been established and much better terms have been negotiated in a number of projects. As is the case in Maharashtra, state regulatory authorities will increasingly insist on merit order despatch. This will require that all new plants ensure that their tariff is such that they are fairly high up on the merit order so as to achieve the planned plant load factor. Competitive bidding along with stable fuel prices would guarantee the success of individual projects as well as that of power sector reforms.

Fertilizers

Growth of the fertilizer industry

The increase in fertilizer consumption has contributed significantly to a more or less sustained improvement in the production of foodgrains in the country which has risen from a level of 52 million tonnes in 1951-52 to 202 million tonnes in

1998-99.

Although the average per hectare consumption of fertilizer nutrients has increased from less than 1 kg. in 1952-52 to about 90.04 kg. in 1998-99, even this level of fertilizer use is low with reference to the objective of accelerating growth in the agriculture sector as well as the consumption levels prevailing in other countries including some of the developing countries in Asia. Moreover, the consumption of chemical fertilizers in the country is unevenly distributed, being much higher in regions with assured irrigation.

The Indian fertilizer industry has been supplying a substantial portion of the growing demand of fertilizers. It had a beginning in 1906, when the first manufacturing unit was set up in Ranipet near Chennai with a production capacity of 6000 TPA of Single Superphosphate. The Fertilizer and Chemicals Travancore Ltd. (FACT) at Cochin in Kerala and the Fertilizer Corporation on India Ltd. at Sindri in Bihar were the first large sized fertilizer plants to be set up in the forties and fifties with a view to establishing a base for industrialization and achieving self-sufficiency in foodgrains. The Green Revolution in the late sixties gave an impetus to the growth of the fertilizer industry in India. The eighties witnessed a significant addition to the fertilizer production capacity.

The installed capacity as on 29.2.2000 has reached a level of 11.71 million MT of nitrogen (inclusive of an installed capacity of 20.67 million MT of urea) and 3.65 million MT of phosphate nutrients, making India the third largest fertilizer producer in the world. The rapid build-up of fertilizer production capacity in the country has been achieved as a result of a favourable policy environment and substantial investments made over the years in the public, co-operative and private sectors. Today, there are 64 large sized fertilizer plants in the country, manufacturing a wide range of nitrogenous, phosphatic and complex fertilizers. Of the three main nutrients required for various crops – nitrogen, phosphate and potash, indigenous raw materials are available mainly for nitrogen. The Government's policy has aimed at achieving the maximum possible degree of self-sufficiency in the production of nitrogenous fertilizers based on utilization of indigenous feedstock. As of now, the country is self-sufficient to the extent of about 92.1% in the case of nitrogen.

To encourage investment in the fertilizer sector, the government has allowed the following concessions to the domestic industry:

- Concessional customs duty benefit on import of capital goods for setting up of new plants / substantial expansion / renovation / modernization of existing units.
- Deemed export benefits to indigenous supplies of capital goods to new / revamped / retrofit / modernization of fertilizer projects, provided such supplies

are made under the procedure of international competitive bidding and no price preference is given to indigenous vendors.

Fertilizer projects now under implementation in the country would add a capacity of 0.5 MMTPA of urea. An 'in principle' approval has also been given to the following four projects for urea capacity creation (3.07 MMTPA)

- Hazira Expansion Project of KRIBHCO at Hazira, Gujarat
- Thal Expansion Project of RCF at Thal, Maharashtra
- Gorakhpur Project of KRIBHCO at the site of FCI's old plant at Gorakhpur, UP
- Nellore Grassroots Project of IFFCO at Nellore, Andhra Pradesh

The initiatives undertaken to set up joint venture projects in countries with better resource endowments so as to meet the growing demand of fertilizers in the country have made significant progress. The Government has approved the investment of NFL/KRIBHCO to make an equity contribution of $69 million each in a joint venture in Oman for production of 1.45 million tonnes of urea and 0.33 million tonnes of merchant ammonia per annum. The Joint Venture Company i.e. Oman India Fertilizer Company has been registered in Oman on 18.2.1998. However, primarily on account of the continuous and significant dip in the international market, the project proposal is being revised and restructured. The revised proposal is being processed for obtaining the approval of the Government.

Feedstocks

Prior to 1980, nitrogenous fertilizer plants were based mainly on naphtha as feedstock. A number of fuel oil based ammonia-urea plants were also set up during 1978 to 1982. In 1980, two coal-based plants were set up for the first time in the country at Talcher (Orissa) and Ramagundam (Andhra Pradesh). With associated and free gas becoming available from offshore Bombay High and South Bassein basins, a number of gas based ammonia-urea plants have been set up since 1985. In view of the limitations on availability of gas, a number of expansion projects were taken up in the last few years with naphtha as feedstock with the flexibility for switching over to gas when available. The Department of Fertilizers has set up a Core Group of Fertilizer Companies to explore the feasibility of importing LNG by forming a consortium of fertilizer companies, along with other interested economic operators, for fertilizer sector in particular and other complementary sectors such as power, domestic fuel etc. One of the options considered envisages the installation of a regasification facility at Kishorprasad in Orissa and the construction of a pipeline connecting the fertilizer plants in the eastern sector with an inter-link to the HBJ pipeline. Existing naphtha based units such as IFFCO-Phulpur, DIL-Kanpur, Nangal, Panipat and Bhatinda units of NFL and new projects like KRIBHCO-Gorakhpur could also be served by this system. The report of the Core Group is being examined by the Government.

The Fertiliser Association of India has estimated that the consumption of urea would go up to 48 million tonnes in 2012. On grounds of food security, the government would like to maximise domestic production capacity. The international urea price has shown sharp increases whenever India and China have increased their imports. Accordingly the government plans to limit imports to around 10% of the requirement. This would mean that another 20 million tonnes of new capacity needs to be set up. This additional capacity can only be gas/ LNG based. These units would be under a strong competitive pressure from imported urea and would have to be protected by a suitable tariff.

Pricing of Urea

Prices of urea are controlled by Government. Fertiliser plants operate under a Retention Pricing Mechanism somewhat similar to the Administrated Pricing Mechanism for the Petroleum Industry.

The government has attempted in the past to decontrol urea prices but has not been able to do so under pressure from cultivators. The Expenditure Reforms Commission (ERC) has now recommended that urea prices be decontrolled by 2006. There is considerable uncertainty as to whether this can be done. There is also some uncertainty on how the WTO obligations would affect the agriculture sector, especially the production of fertiliser intensive foodgrains.

The impact of the ERC recommendations on the fertilizer industry and competitiveness of LNG are covered in the following chapter.

4

Inter fuel economics

Introduction

The power and fertiliser sectors are the anchor customers for gas. The competing fuel for gas in power generation is coal. In the fertiliser sector, gas has to compete with naphtha and imported urea. To assess the competitiveness of gas vis-à-vis other fuels, the imputed values or replacement values of gas in power generation, urea production and industries in general have been estimated. Imputed value of gas is the price of gas at which the cost of generation/production in a gas based plant equals the cost of generation/production using an alternative fuel, at a particular location. Thus it indicates the maximum price for gas to make it competitive with alternative fuels. The methodology used has been illustrated in Table 4.1 below.

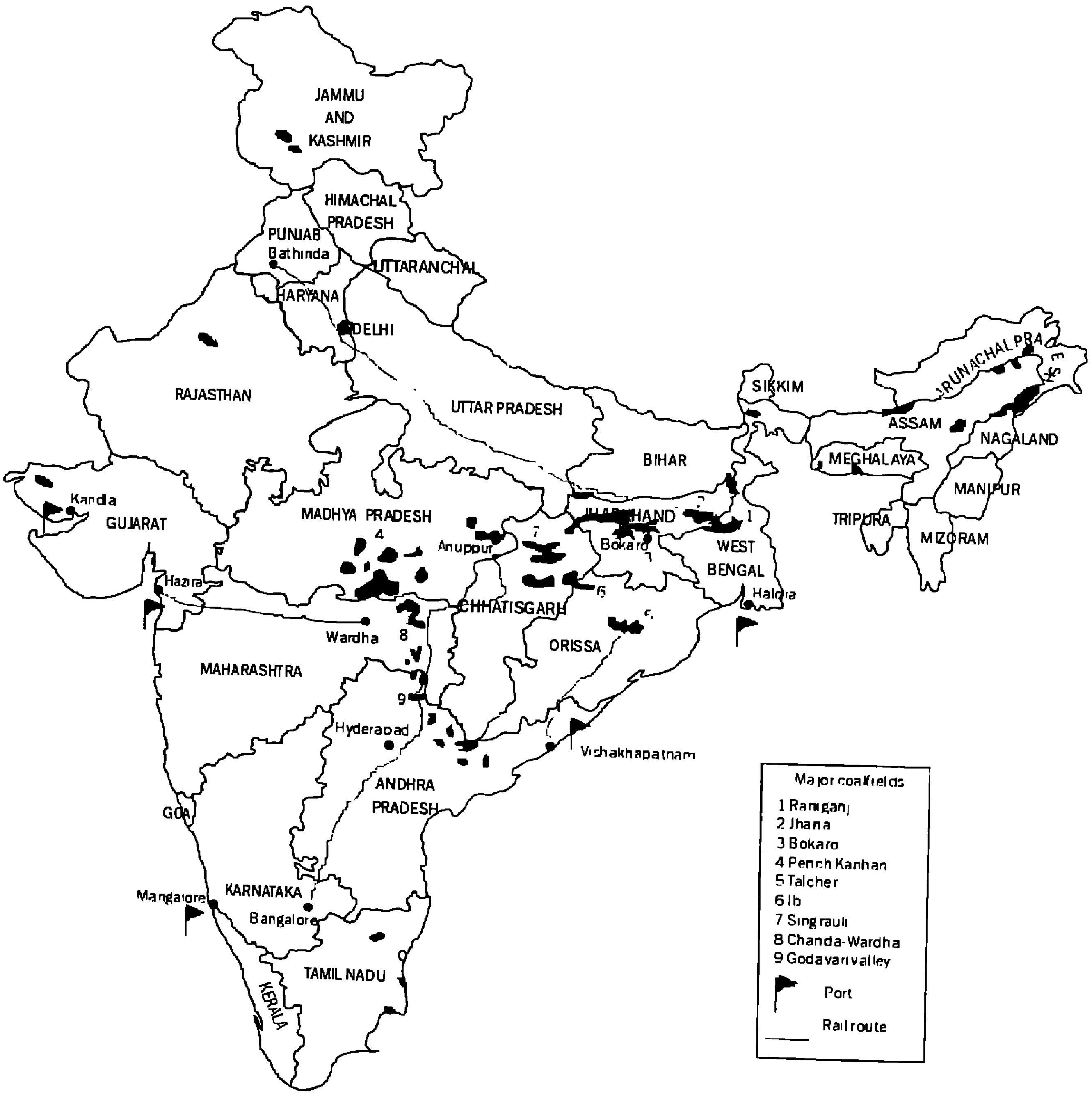
Table 4.1 Methodology for calculating imputed value of gas

Cost of generation/production	Gas based	Competing technology
Capital cost	a	c
Operation and maintenance cost	b	d
Fuel cost	X (*unknown*)	e
Total cost		f = c + d + e
Imputed value of gas		X = f - a - b

Five locations in India have been considered for estimation purposes – Visakhapatnam on the east coast of India, Bangalore in the south, Hazira on the west coast and Bathinda and Bokaro in the north and east respectively. Coal supply linkages in India are fixed by the Standing Linkage Committee based on quality and quantity of coal required and Indian Railways ability to transport the coal.

The locations, ports and coal linkages considered have been mapped in Figure 4.1.

Figure 4.1 Major Coalfields in India



The ports for these locations where imported coal, naphtha and urea can land have been listed in Table 4.2. Also, the domestic coalfields with which the selected locations have coal linkages have been tabulated below. All the companies operating these fields are subsidiaries of Coal India Limited (CIL).

Table 4.2 Locations, ports and coalfields

Locations	Port	Domestic coalfields
Visakhapatnam	Visakhapatnam	Talcher, Ib (Mahanadi Coalfields Limited - MCL)
Bangalore	Mangalore	Annuppur (South Eastern Coalfields Limited - SECL)
Hazira	Hazira	Wardha (Western Coalfields Limited - WCL)
Bathinda	Kandla	Jharia (Bharat Coking Coal Limited - BCCL)
Bokaro	Haldia	Bokaro (Bharat Coking Coal Limited - BCCL)

The power sector

In India, coal among all fuels has the largest share in total installed capacity. Imputed values of gas in power generation have been calculated for both domestic and imported coal, at each reference location.

Imported coal has a higher calorific value (6400 kcal/kg) than domestic power grade coal (4000 kcal/kg) but domestic coal has a higher ash content (about 40%) compared to imported coal (15%). Thus use of domestic coal results in additional ash generation of about 0.25 MT per MT of coal consumed. Imported coal has a greater sulphur content than Indian coal which entails an additional capital cost (about Rs 4.5 million) for installing a flue gas desulphurisation unit.

Till date India has operated only subcritical coal based power plants for commercial power generation. NTPC plans a 660 MW supercritical coal power unit at Seepat by 2006-07, More supercritical coal plants in the future are a distinct possibility. Hence in this analysis technologies of subcritical as well as supercritical coal power plants have been considered. A coal based power plant has typically lower efficiency of about 37% for a subcritical unit and 39.1% for a supercritical unit, compared to 50% above for a gas-based one. Also, coal-based plants in India maintain 15 to 30 days coal stock to avoid shutting down in case of supply shortages.

Indigenous coal prices have been decontrolled from January 2000 with an objective of levelling the prices at import parity. However, till date, coal prices are determined by CIL for all its fields. The fuel costs, at each location, are the basic fuel prices plus the transportation costs (from ports for imported fuels and domestic fields for indigenous coal), which are distance related.

Though naphtha is used for power generation in India, the cost of generation is generally higher than with coal or gas. Internationally naphtha is not considered as a suitable fuel for power generation.

Methodology for imputed value calculations

Capital cost per unit of power, including interest during the construction period (IDC), are annuitised using the capital recovery factor (which is determined by the operating life of the project and the discount/interest rate). Annual generation, determined by the plant load factor (PLF) are netted for auxiliary consumption to arrive at the net units sent out in a year. These together provide the capital cost per unit of power sent out which together with the O&M costs and the fuel costs per unit of power give the total cost of generation of an unit of electricity.

Assumptions

Delivered costs of imported coal

- The Indian steam coal import cif price has been considered equivalent to cif of coal landing at Japanese ports as the distance from Australia or Indonesia to Japan is about the same as that to India.
- The Asian McCloskey Steam Coal Marker (cif Japan) has varied within the band of $ 40-50 /MT over 1987-1999. As on October 18, 2000, it was $ 34 /MT. For imputed value estimations, two scenarios of cif prices of imported coal at Indian ports have been considered: cif at the current marker price of $ 34 /MT and also at $ 45 /MT.
- An exchange rate of Rs 46 per US dollar has been assumed.
- Import duties and port storage and handling charges are added to the cif price to derive the landed cost of coal.
- The import duty structure for all fuels conform to prevailing customs and excise rates in India. The port storage and handling charges are only indicative of the actual charges.
- The delivered prices of imported coal include railway freight charges from ports to the reference locations.

Delivered costs of domestic coal

- Use of F-grade coal for power plants has been assumed.
- Current power coal prices (without taxes) from Talcher is Rs 351/MT.
- As per UNDP-ESMAP report, long run marginal economic cost (LRMC) of production of domestic power-grade coal from Talcher is Rs 540/MT. LRMCs of coal from other fields are not available, hence current prices of coal from other fields have been scaled in proportion to Talcher coal prices and taxes added thereafter to obtain representative figures for LRMCs of coal from each field.

- Delivered prices of domestic coal include rail freight from the field to the location with which it is linked.
- Imputed values for gas have been assessed against current prices as well as LRMCs of domestic coal.

Technical and financial parameters

- Technologies considered for power generation are:
  - — combined cycle advanced class gas turbines;
  - — pulverised subcritical coal-based plant;
  - — supercritical coal-based plant

The technical and financial parameters of such plants are based on views of industry experts from the National Thermal Power Corporation (NTPC) and Central Electricity Authority (CEA) and Bharat Heavy Electricals Limited (BHEL)..

Table 4.3 Technical and Financial Parameters for Combined Cycle Advanced Class gas Turbines

S.No.	Technical parameters	Units	Value
1	Plant load factor	%	80
2	Auxiliary consumption	%	3
3	Life of plant	Years	30
4	Calorific value	kcal/Nm^3	8500
5	Heat rate per unit sent out	kcal/kWh	1583

S.No.	Financial parameters	Units	Value
1	Discount rate	%	12
2	Capital cost per MW	Rs. Million	30
3	Fixed operating cost as % of capital cost	%	2.0
4	Investment period	Years	3

Contemporary combined cycle gas turbines in India have an efficiency of around 52-53%. However Dabhol operates an advanced class gas turbine. The Tamil Nadu Electricity Board has planned two such plants and Gujarat Electricity Board one in their states. In the private sector Mitsubishi and ABB have also ordered advanced class CCGT plants in 2000. BHEL and NTPC have provided the corresponding cost, plant load factor and auxiliary consumption figures.

Table 4.4 Technical and Financial Parameters for Subcritical Coal Plants

S.No	Technical parameters	Units	Value
1	Plant load factor	%	75
2	Auxiliary consumption (Indigenous coal)	%	8.0
3	Auxiliary consumption (imported coal)	%	8.5
4	Life of plant	Years	30
5	Calorific value (indigenous coal)	kcal/kg	4000
6	Calorific value (imported coal)	kcal/kg	6400
7	Heat rate per unit sent out (indigenous coal)	kcal/kWh	2526
8	Heat rate per unit sent out (imported coal)	kcal/kWh	2540

S.No	Financial parameters	Units	Value
1	Discount rate	%	12
2	Capital cost per MW (indigenous coal based)	Rs. Million	45
3	Capital cost per MW (imported coal based)	Rs. Million	49.5
4	Fixed operating cost as % of capital cost	%	2.5
5	Investment period	Years	4

Table 4.5 Technical and Financial Parameters for Supercritical Coal Plants

S.No	Technical parameters	Units	Value
1	Plant load factor	%	75
2	Auxiliary consumption (indigenous coal)	%	8.5
3	Auxiliary consumption (imported coal)	%	9.0
4	Life of plant	Years	30
5	Calorific value (indigenous coal)	kcal/kg	4000
6	Calorific value (imported coal)	kcal/kg	6400
7	Heat rate per unit sent out (indigenous coal)	kcal/kWh	2404
8	Heat rate per unit sent out (imported coal)	kcal/kWh	2417

S.No	Financial parameters	Units	Value
1	Discount rate	%	12
2	Capital cost per MW (indigenous coal based)	Rs. Million	45
3	Capital cost per MW (imported coal based)	Rs. Million	49.5
4	Fixed operating cost as % of capital cost	%	2.5
5	Investment period	Years	4

Imputed values of gas in power generation

The delivered prices and cost of power generation using domestic and imported coal have been presented in Figure 4.2 and 4.3 respectively.

Figure 4.2 Delivered Prices of Fuels ($/MMBtu)

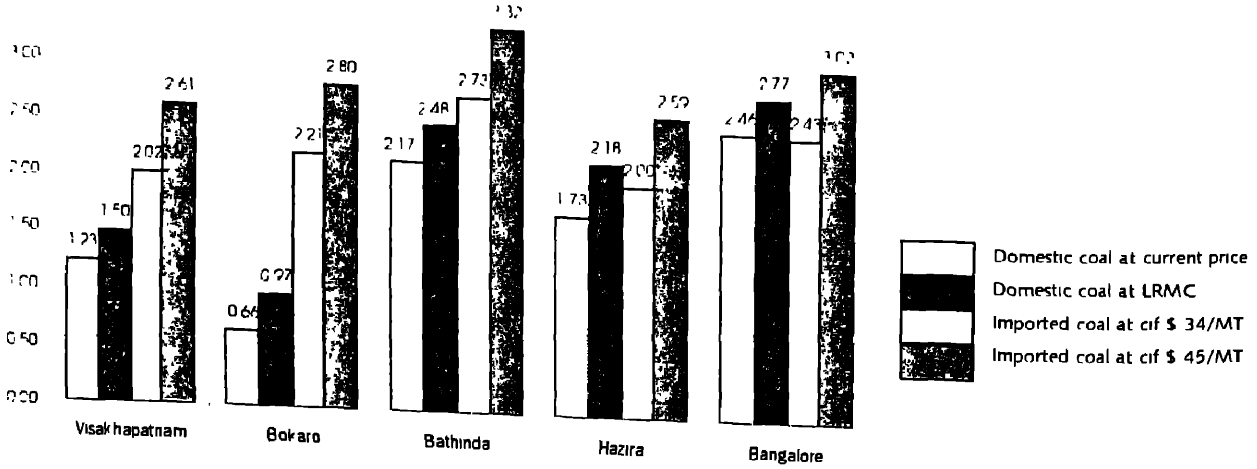


Figure 4.2 illustrates that delivered cost of domestic coal is lower than imported coal at all locations except at Hazira, a port location, and Bangalore which is far moved from the source of domestic coal supply.

Figure 4.3(a) Cost of Power Generation in a Subcritical Coal Plant (Rs/kWh)

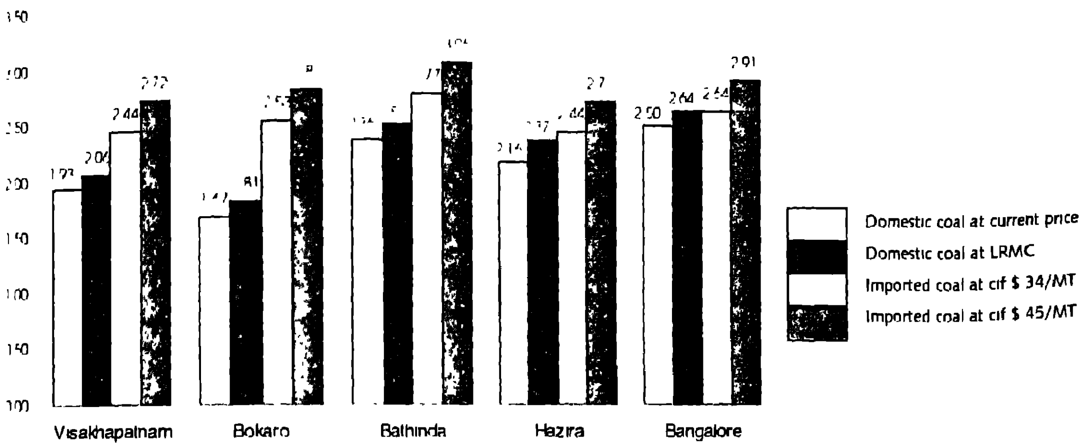
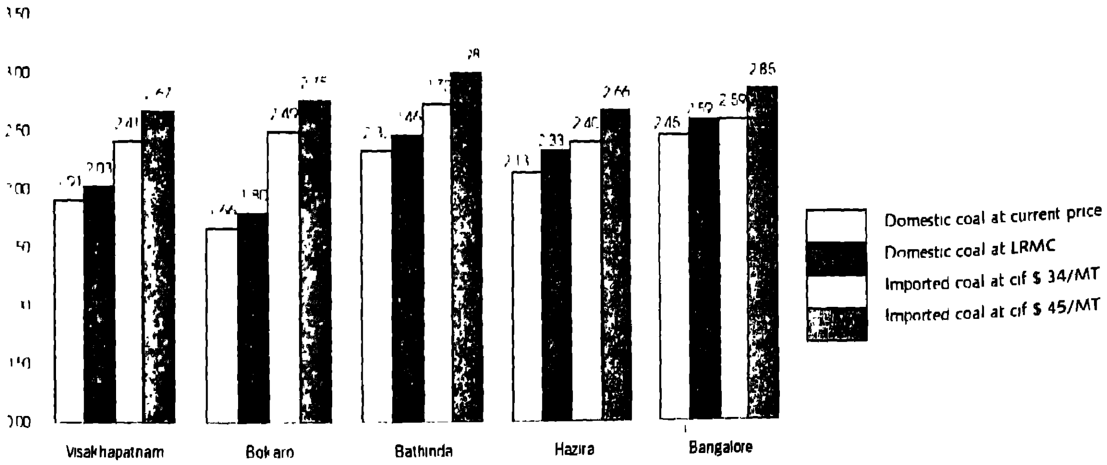


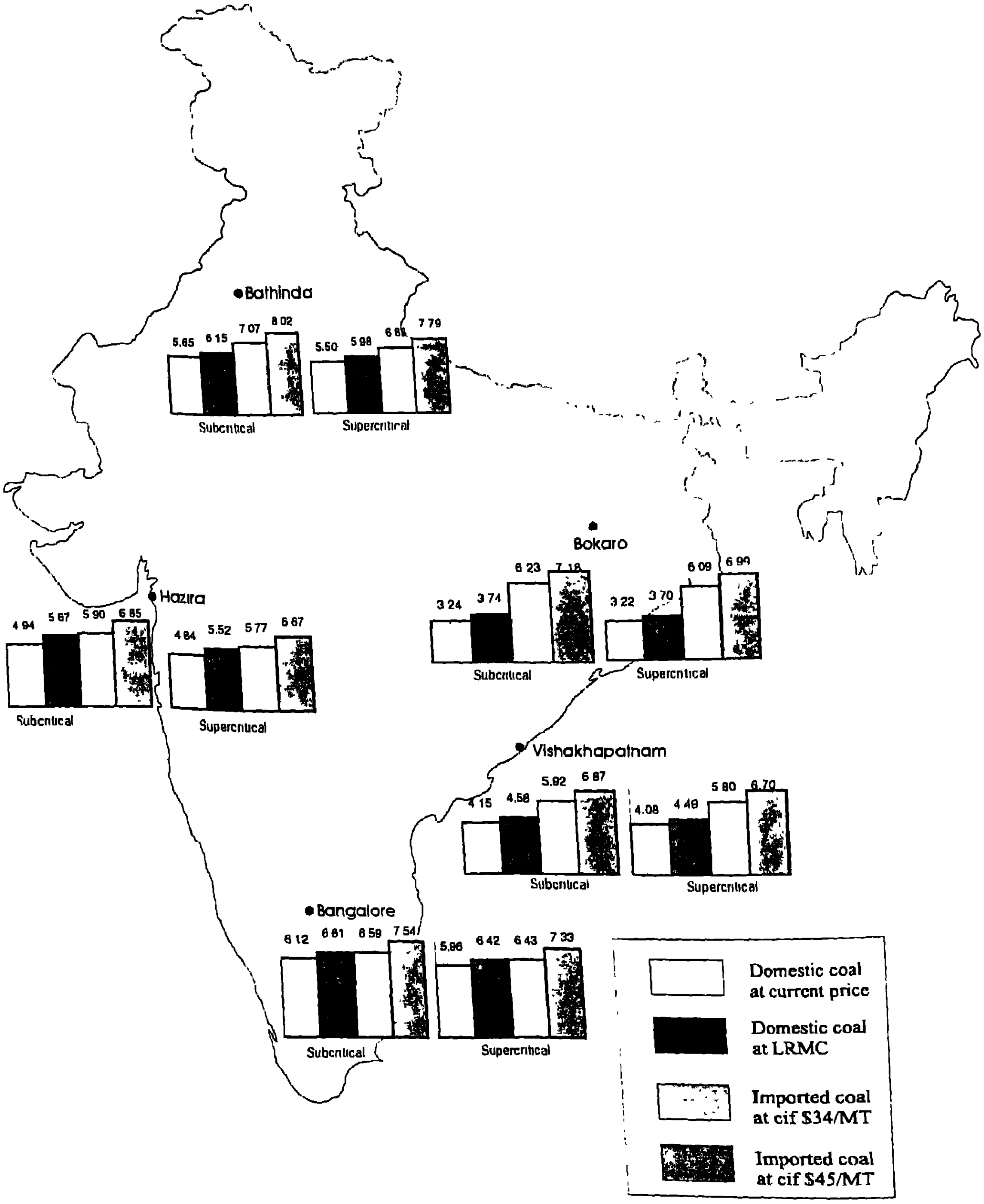
Figure 4.3(b) Cost of Power Generation in a Supercritical Coal Plant (Rs/kWh)



Despite the fact that Indian power grade coal is low in calorific value and has to be transported over long distances, the cost of power generation at all locations is lower compared to imported coal (Figure 4.3 (a), (b)) except at Bangalore where at LRMC it is at par with imported coal (cif $ 34/MT) due to the long transport lead.

The imputed values of gas in power generation have been presented in Figure 4.4.

Figure 4.4 Imputed Values of Gas in Power Generation ($/MMBtu)



Visakhapatnam

Though Visakhapatnam is a port location, it will be more economical to use indigenous coal than imported coal in power generation, because Visakhapatnam is close to Talcher coalfields. Also, Talcher has the lowest coal prices among all coalfields. Gas will be able to compete with domestic coal at prices around $4/MMBtu.

Bokaro

Being a pithead location, Bokaro has the lowest imputed value of gas against domestic coal. If gas from Bangladesh can be made available in this region at about $ 3/MMBtu it can compete with domestic coal at this location.

Bathinda

If delivered price of gas from the west coast of India to Bathinda is around $ 5/MMBtu it will be competitive against domestic coal.

Hazira

If gas prices can be kept below $ 5/MMBtu, it can replace coal in power generation.

Bangalore

This location is far moved from its source of domestic coal. At low cif prices, imported coal is at par with domestic coal in power generation. Once again, if gas is made available at Bangalore at prices around $ 6/MMBtu, it will compete with coal in power generation.

The fertiliser industry

The fertiliser industry is currently the single largest gas consumer in India which is used as a feedstock for the production of ammonia and subsequently, urea.

Alternative technologies

The alternative feedstocks to gas in urea production are naphtha and fuel oil. Fertiliser production with fuel oil is practically an outdated technology. Moreover, the capital costs of fuel oil based urea plants are significantly higher than those based on natural gas due to the necessity of installing desulphurisation equipment, pre-heating equipment and gear pumps due to the high viscosity of fuel oil. The filtration requirements are also greater with fuel oil. For comparison the imputed values of gas have been assessed against naphtha and also imported urea.

Methodology for imputed value calculations

The capital cost (including IDC) of gas and naphtha-based plants are annuitised using CRF to arrive at the annuitised capital cost per unit of urea production. The fuel cost and O&M cost are added to the derived capital cost to generate the total cost of production per MT of urea. The capital cost and O&M of gas-based plants are subtracted from the per unit cost of urea production in the naphtha-based plant to derive the maximum at which gas can be priced so that it can compete with naphtha. To estimate the competitive price of gas against urea imports, the capital cost and O&M of gas-based plants are subtracted from delivered cost of imported urea at the respective locations.

Assumptions

Delivered prices of naphtha and imported urea

- As naphtha prices in India have been decontrolled and linked to international prices with effect from April 1998, import parity prices of naphtha have been used for all estimations.
- The fob-Middle East naphtha prices have been regressed against fob-Middle East crude oil prices, over March 1996 to June 2000, to assess the prices of naphtha when crude oil prices are at $ 20/bbl (a low price scenario) and $ 30/bbl (a high price scenario).
- The insurance, sea freight and port storage and handling charges are added to derive the landed cost of naphtha at Indian ports.
- At present in India there are no customs duty or CVD on imports of naphtha for use in fertiliser industry.
- The Second Report of Expenditure Reforms Commission (ERC) has considered a long run average cost of imported urea at $ 150/MT (cif) as a benchmark figure. The landed cost of imported urea at the Indian coast at $ 150/MT, assuming an exchange rate of Rs 46 per US dollar, is Rs 6900/MT.
- Currently there are no import duties on urea in India.
- Rail freight is added to landed cost to arrive at the delivered costs of imported urea and naphtha at the respective locations.

Technical and financial parameters of an urea plant

The following technical and financial parameters of gas/naphtha based urea plants conform to views of experts from the Fertiliser Association of India (FAI) and assumptions of the High Powered Committee on 'Fertilizer Pricing Policy'.

Table 4.6 Technical and financial parameters of a typical gas based urea plant

S.No.	Parameter	Unit	Value
Technical parameters			
1	Urea capacity	Tons/year	726,000
2	Energy required per ton of urea	Gcal/ton	5.40
3	Calorific value of gas	kcal/Nm^3	8500
4	Life of plant	Years	15
Financial parameters			
5	Discount rate	%	12
6	Capital cost (new plant)	Rs. Million	17,000
8	Fixed operating cost	Rs/Ton	854
9	Investment period	Years	3

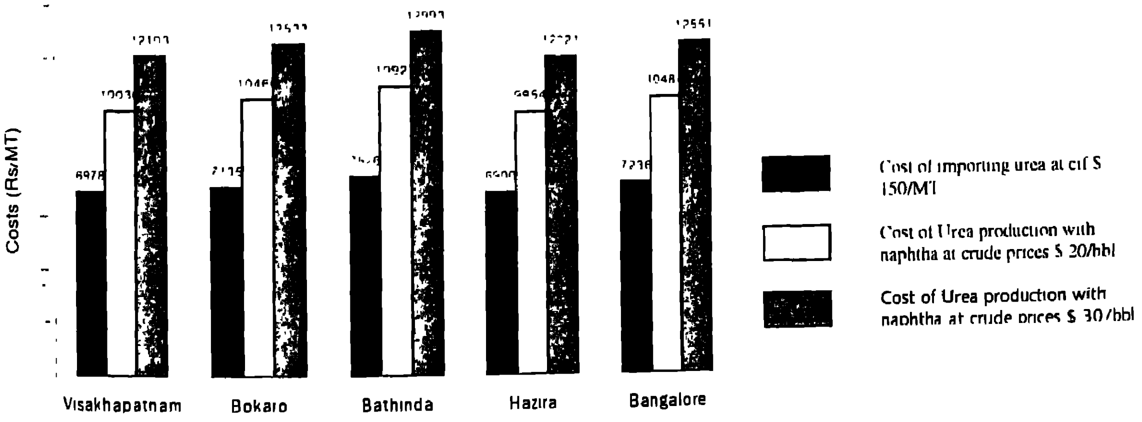
Table 4.7 Technical and financial parameters of a typical naphtha based urea plant

S.No.	Parameter	Unit	Value
Technical parameters			
1	Urea capacity	Tons/year	726,000
2	Energy required per ton of urea	Gcal/ton	5.10
3	Calorific value of naphtha	kcal/kg	10560
4	Life of plant	Years	15
Financial parameters			
5	Discount rate	%	12
6	Capital cost (new plant)	Rs. Million	17,500
8	Fixed operating cost	Rs/Ton	924
9	Investment period	Years	3

Imputed values of gas in urea production

The delivered costs of imported urea, cost of urea production with naphtha and imputed values against naphtha and imported urea have been presented in Figures 4.5 and 4.6.

Figure 4.5 Delivered cost of imported urea and cost of urea production with naphtha



The cost of importing urea is far cheaper than the cost of urea production from naphtha at all the locations considered.

Figure 4.6 Imputed Values of Gas in Urea Production ($/MMBtu)

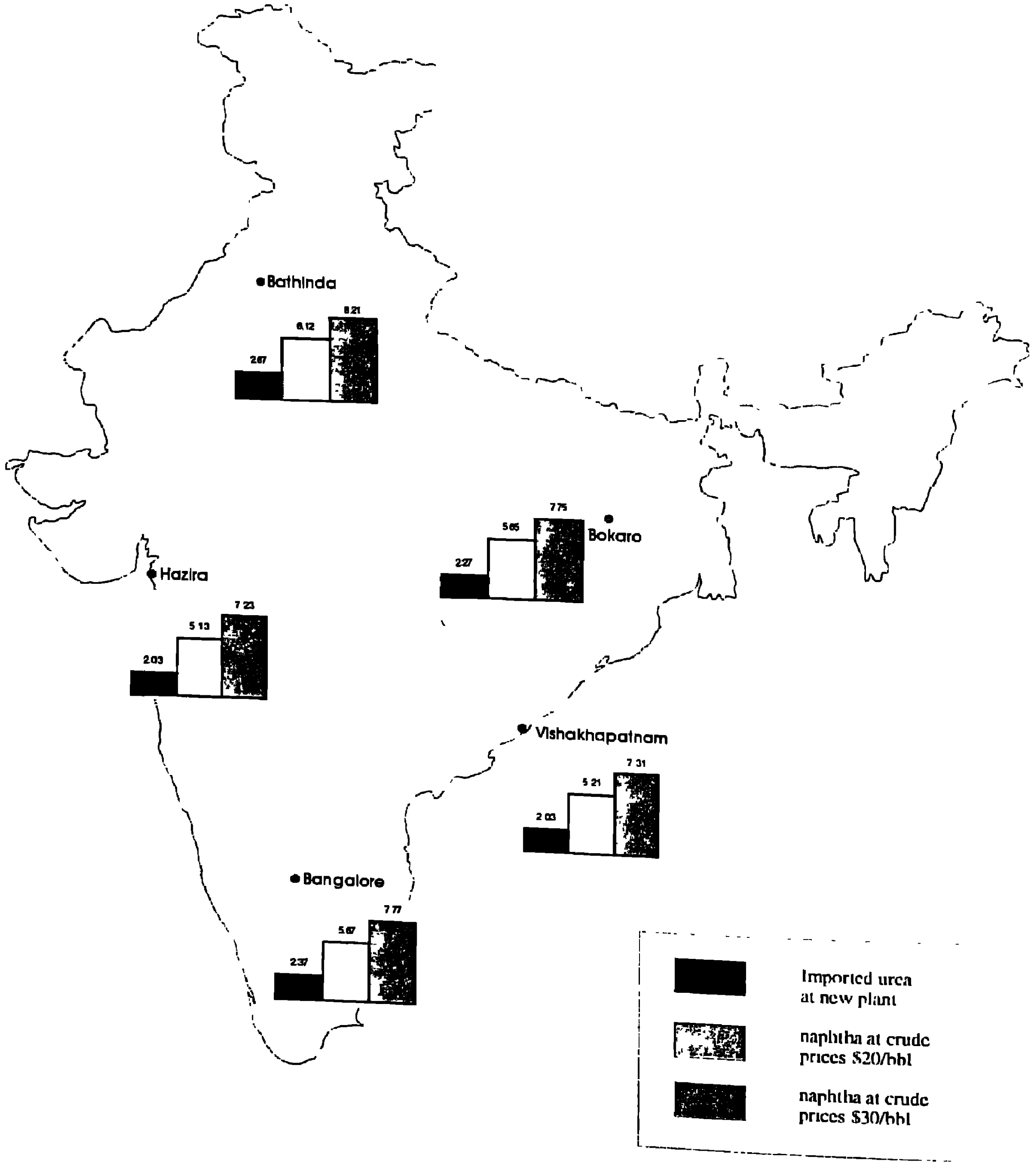


Figure 4.6 illustrates that imputed values of gas against naphtha, even in the low price scenario, range from 5.13-6.12 $/MMBtu at the locations considered for this analysis. Gas at prices around $ 5/MMBtu will be able to replace naphtha at all the locations.

From Figure 4.6, imputed value of gas against urea imports is the highest at Bathinda ($ 2.67/MMBtu). If gas is available at around $ 4/MMBtu at the west coast, the delivered prices around Bathinda will be even higher. Hence gas for urea production cannot compete with urea imports at cif $ 150/MT at any of the locations considered.

Indigenous manufacture versus imports

Though the economics of importing urea apparently seem attractive, it has been experienced that when India makes large purchases in the international market it pushes up urea prices. India is the second largest urea importer in the world. In 1995-96 India increased urea imports to 21% of total consumption. Consequently in 1996, India had to pay as much as $ 250/MT for urea imports. At such high prices, imputed values of gas range between $ 6.70 - 7.34/MMBtu at the five locations considered in this analysis. Then gas in urea production becomes very competitive vis-à-vis urea imports. More than marginal dependence on imports raises questions about food security. Any disruption in urea supply will have significant adverse impacts on agricultural production. Hence the emphasis is on self-sufficiency in domestic urea production. The Hydrocarbon Vision 2025 Sub-group on development and utilization of Natural gas assumes only 2 MMT of urea imports each year till 2025. Consequently urea imports is expected to account for only about 10% of total urea demand.

Decontrol of the fertilizer (urea) industry

The ERC recommends decontrol of the urea industry in a manner by which the domestic industry will not only be able to compete with urea imports but also attain self-sufficiency in urea production. The Commission recognises that a sudden decontrol of the urea industry could lead to shutting down of most naphtha based units as even their short run variable costs would exceed the price of imported urea. The resultant increase in urea imports would push up urea prices in the international markets and the subsidy outgo could be even higher than the present. The Commission recommends use of natural gas in urea production. However, on account of limited availability of gas, the ERC suggests that plants based on other feedstock have to be compensated for higher cost of feedstock in order to maintain self-sufficiency in urea production. On these grounds the ERC proposes a phased decontrol of the system.

The ERC proposals have two aspects:

1. The Commission suggests a 7% increase in the price of urea in real terms from the current retail price of Rs 4,600/MT every year from 1.4.2001. The open market price will reach about Rs 7,000/MT by 1.4.2006, a level at which the industry can be freed from all controls and be required to compete with urea imports at cif $ 150/MT. When urea import prices dip below $150/MT, duties are to be levied to ensure that such imports reach the farmgate at Rs 7,000/MT.
2. The Commission suggests a Group Concession Scheme with 5 different categorisation of existing units - pre and post 1992 gas based units, naphtha based units, FO/LSHS based units and mixed feedstock units. The plants would be eligible for concessions depending on the category under which they are placed. The concessions would be decreased over the years till 2006 when LNG/naphtha based units will be eligible for a 'Feedstock Differential Cost Reimbursement' (FDCR) of Rs 1,900/MT. The ERC deems that the existing gas (domestic) based plants, FO/LSHS or mixed feedstock based plants will not need any concession from April 2006. This conclusion has been reached in light of the present domestic gas prices at Rs 2150 - 2850/thousand cubic metres. The Ministry of Petroleum and Natural Gas is contemplating a doubling of domestic gas prices to over Rs 5000/thousand cubic metres. However, by 2006, the existing urea units would be depreciated considerably and most of the capital investments would be recovered. Consequently, these plants will be able to afford higher fuel prices. In case domestic gas prices become unaffordable by existing gas units, the concessions to these units have to be revised to ensure self-sufficiency in urea production.

A phased decontrol of urea industry has been initiated in February 2001 in accordance with ERC recommendations. The Union Budget 2001/2002 has announced discontinuation of the Retention Price Scheme and a Group Concession Scheme with revision of concessions every three months.

Complete implementation of ERC proposals would have some implications for the maximum price payable for gas in new LNG based urea units. According to ERC, urea producers will receive Rs 8,900/MT of urea produced. Assuming Rs 400/MT as the distribution and marketing expenses, net value to urea producers would be about Rs 8,500/MT. Subtracting capital and O&M costs of a new gas based urea unit would give the maximum price payable for gas in urea production, i.e. $ 3.66/MMBtu. Consequently viability of LNG based urea plants will be restricted to only select regions in India. This will call for a revision of concessions to LNG urea units mainly due to two reasons – to ensure self-sufficiency and to ensure maximum use of gas in urea production as gas is the cheapest option among all alternative fuels like naphtha and FO.

General industries

Methodology for imputed value calculations

Industries use coal, fuel oil and LPG as an underboiler fuel or for providing heat for process operations. Certain industries i.e. refractories, glass and ceramic manufacturers require clean fuels such as LPG or natural gas for quality control reasons. Imputed values of gas have been computed on a simple calorie equivalence basis for the above three fuels.

Assumptions

- The calorific values of different fuels for industrial use are given in Table 4.8. Domestic D-grade coal is superior to F-grade (for power sector) and also priced higher.
- Indigenous coal for industries will be supplied to the respective locations from the coalfields as mentioned in Table 4.2. Only D-grade coal for industrial use in Andhra Pradesh will be sourced from Ib in Orissa as Talcher does not produce any D-grade coal.

Table 4.8 Calorific value of fuels

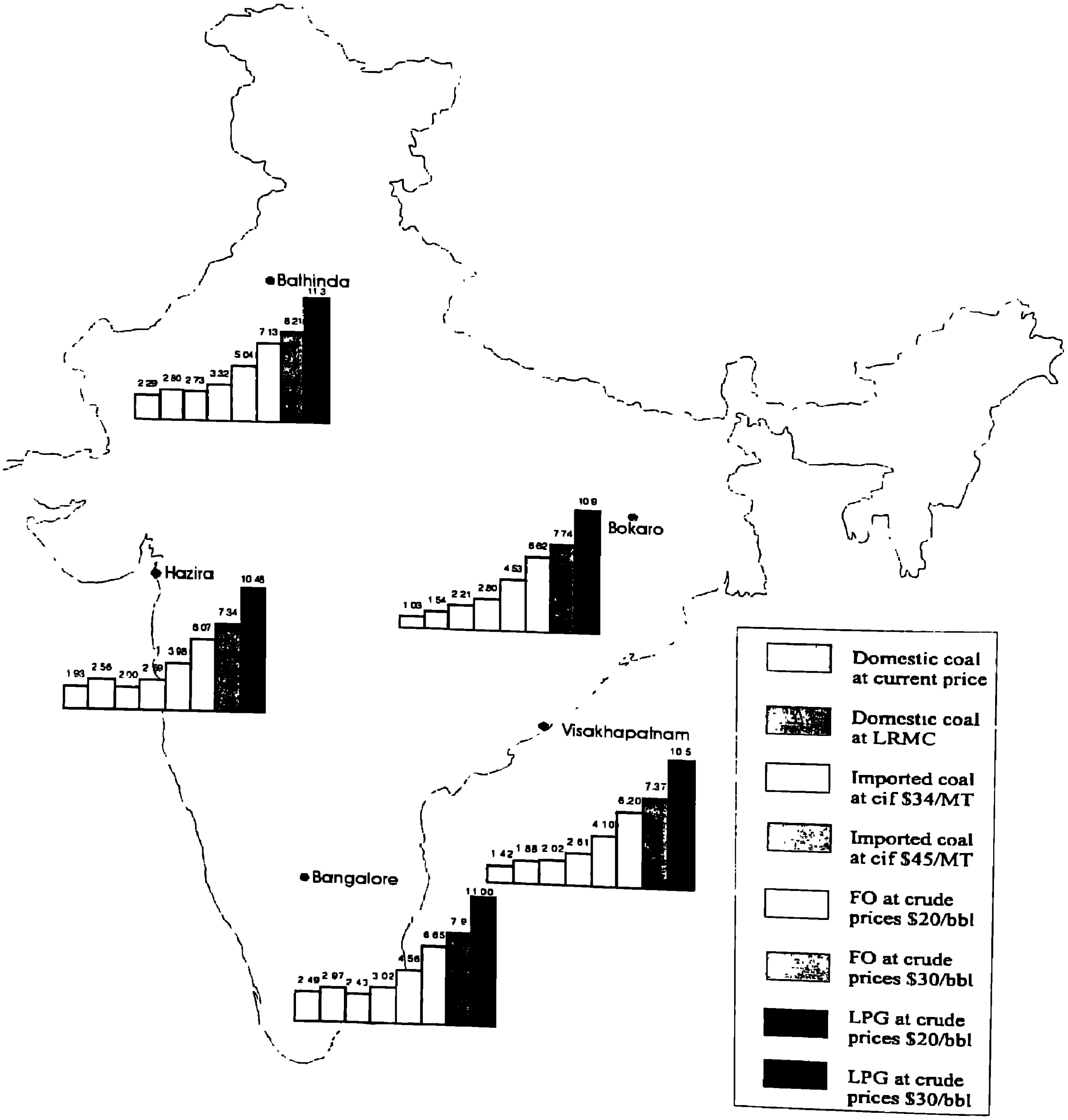
Fuels	Calorific value (kcal/kg)
Domestic D-grade coal	4800
Imported coal	6400
Fuel oil (FO)	10440
LPG	11300

- LRMCs of D-grade coal are not available. The current prices of D-grade coal for industries are appreciated in accordance with power coal prices of Talcher. Taxes are added to derive the LRMCs. These derived LRMCs of D-grade coal as well as the current prices have been considered for imputed value estimations for industries.
- Other fuels, namely FO and LPG are priced on import parity basis. The prices of FO and LPG have once again been evaluated at crude oil prices of $ 20/bbl and $ 30/bbl (fob-Middle East).
- Rail freight is added to prices of domestic coal and to landed costs of FO and LPG to determine their delivered prices to the respective locations.

Imputed values of gas in general industries

The imputed values of gas for industries at each reference location are shown in Figure 4.7.

Figure 4.7 Imputed Values of Gas in Other Industries ($/MMBtu)



- Imputed values indicate that it is most economical to use coal (domestic or imported) as industrial fuel.

Visakhapatnam

In spite of being a port location, it will be economical to use domestic coal rather than imported coal as Visakhapatnam is not very far from Ib fields.

Bokaro

Being a pithead location domestic coal is the cheapest option.

Bathinda

Domestic coal at current price is the cheapest option. Imported coal at low cif prices will be cheaper than indigenous coal at LRMC.

Hazira

Being a port location, imported coal is cheaper than indigenous coal at LRMC when cif is low and only marginally costlier when cif is high. However, domestic coal at current prices is the cheapest alternative.

Bangalore

This location is far moved from Annuppur region, so imported coal will be cheaper than domestic coal when cif is low and only marginally dearer when cif is high.

Other factors governing choice of fuels

Combustion efficiencies

Natural gas, LPG and FO have greater combustion efficiencies than coal (domestic or imported). In which case their competitiveness vis-à-vis coal will improve significantly. Also glass and ceramic manufacturing require continuous process heating in a controlled manner which makes gas and LPG fuels preferable to coal.

Imputed values of gas against LPG are very high, averaging around $ 8/MMBtu at low crude price scenario. Given a choice between gas and LPG in glass and ceramic industry, gas will be preferred over LPG.

Decline in consumption of coal

A declining trend in domestic coal use in industries over the past decade is noticed. For example, consumption of indigenous coal in Gujarat cement industries amounted to over 1 MMT in 1990-91. In 1999-00, no domestic coal was used in cement production in Gujarat. Likewise, textile industries in Gujarat had consumed about 0.87 million tonnes of domestic coal in 1990-91 and at present consumes only 18 thousand tonnes. Consumption of domestic coal in industries has declined in most states in India. The monopolistic attitude of CIL is somewhat responsible for this decline. Often the desired quality of coal is not made available by CIL to small industries. In addition delays in coal supply are frequent for these small consumers. Consequently industries are shifting over to imported coal, LPG and natural gas. On economic grounds gas scores over LPG as a cheaper option. Compared to coal, domestic or imported, gas has some obvious advantages. Steam-fired boilers need adequate time to start up or shut down while gas based plants are more flexible. Also gas has a distinct advantage over coal on environmental grounds.

Domestic coal has high ash content which has environmental implications. Industries often face problems of ash disposal. SPM, CO_2, NO_x and SO_2 emissions for domestic coal are considerably higher than that for natural gas. Sulphur content in imported coal is also high while that in natural gas/LNG is negligible.

Coal production and logistical constraints

Though India is a coal rich country, growth rates in coal production seems to be on the decline. The compound annual growth rate of coal production during 1990-95 was a healthy 5% but slowed down to only 2% during 1995-99. It is anticipated that coal production will reach a level of about 450 MMT by 2015. Increases in coal production is primarily restricted to the eastern region of the country. It will be difficult to extend the already saturated rail transport capacity for widespread distribution of coal throughout the country from the eastern region. Industries situated far from sources of domestic coal often face hazards of untimely coal supplies. Coal consumption being small for an industry, wagon loads carry other cargoes along with coal which often lead to delays in coal arrivals.

Thus constraints related to combustion efficiency, transportation, supply and environment have rendered gas a preferred fuel for many industries.

5 Gas demand

Current scenario

Gas utilisation in India started in earnest only after the commissioning of the Hazira-Bijaipur-Jagdishpur (HBJ) gas pipeline in 1986, linking the gas producing areas in the West to the consuming states in the North-western part of the country. The Government appointed a number of committees to assess the best use of domestic gas. Gas was, initially allocated mainly for fertiliser production.

Although the gas industry has witnessed a rapid development since, gas usage accounted for only 8% of the total primary energy consumption in the country in 1999. The structure of gas consumption has also changed. Current gas consumption for power generation equals that for fertiliser production, with each sector accounting for about 40% of the total gas consumption.

Geographically, there are four major areas (basins) of gas production in India (Figure 5.1):

- The Western offshore region
- North and South Gujarat
- The Krishna Godavari basin on the east coast
- Assam, Arunachal Pradesh and Tripura

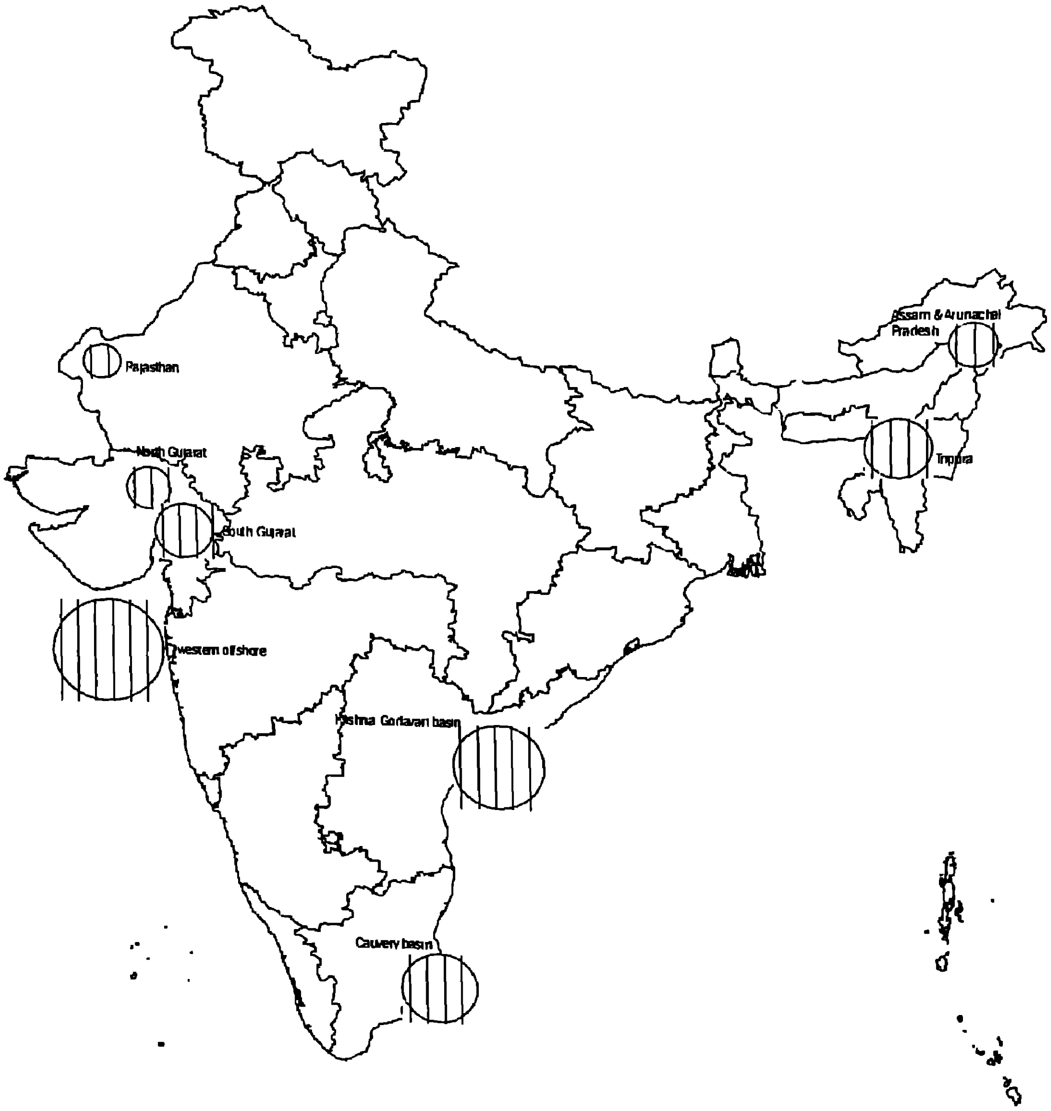
Gas consumption by area and by sector for 1999/00 is summarised in Table 5.1.

Table 5.1 Regional/sectoral gas consumption in 1999/00: MMSCMD

Region/State	Fertiliser	Power	Sponge Iron	Others	Total
Western offshore:					
Uran	4.8	3.6	1.5	0.8	10.6
Hazira	2.8		1.7	0.9	5.3
HBJ	13.4	11.0		2.8	27.3
Sub-Total	**20.9**	**14.6**	**3.1**	**4.5**	**43.1**
Western onshore	1.2	4.1		1.4	6.7
Krishna Godavari Basin	1.8	2.5		0.1	4.3
Rajasthan		0.4			0.4
Cauvery Basin		0.0		0.2	0.2
North east	0.0	1.4		0.1	1.6
Total	**23.9**	**22.9**	**3.1**	**6.4**	**56.4**

Source: Gas Authority of India Ltd (GAIL)

Figure 5.1 Gas producing regions of India



Source: Directorate General Hydrocarbons

Till the late 1980's supply of gas was restricted due to a lack of infrastructure. Gradually, with both supply and demand picking up, the Government had to resort to a system of gas allocations through the inter-ministerial Gas Linkage Committee. Bulk of these allocations, made prior to 1990, took into account ONGC's (Oil & Natural Gas Corporation) estimates of likely gas production in the country. Actual gas production, however, has not matched expectations and as a result allocations far exceed gas sales. While current gas sales aggregate 56 MMSCMD, the total gas allocation is about 110 MMSCMD.

Since current gas allocations far exceed availability, expansion projects of existing consumers/new facilities are being planned on imported gas via pipelines and as LNG. Imported gas is also expected to meet the existing gap between current allocations and sales. The following sections provide a brief summary of the major gas consuming regions. The descriptions include information of key consumers in each region and their plans for expansion, if any. While pipeline projects are still at nascent stages, a number of proposals related to LNG imports are at various stages of development.

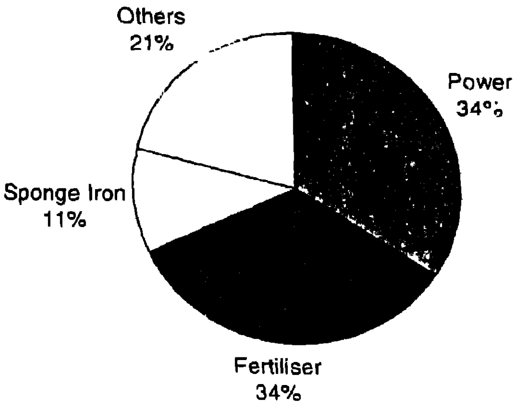
The Western offshore

The Western offshore region can be categorised into three sub-systems: customers in the Uran region in the state of Maharashtra, those at the landfall point of gas from the South Bassein field at Hazira in the state of Gujarat and those along the HBJ pipeline system.

The Uran Region

Against an allocation of 17.6 MMSCMD, the Uran region registered sales of 10.6 MMSCMD in 1999/00. Power and fertiliser sectors account for about a third each of the total gas allocation (Figure 5.2).

Figure 5.2 Sectoral gas allocations in the Uran region



Power sector. The Maharashtra State Electricity Board (MSEB) is responsible for generation & distribution of electricity in the state of Maharashtra. MSEB owns & operate gas-based power plants aggregating 912 MW at Uran (IIL, 2001a). However due to shortage of gas supply from Gas Authority of India Ltd (GAIL), the capacity utilisation had been low till recently. The MSEB has a power purchase agreement with Dabhol Power Corporation (DPC) for power offtake from the 726 MW gas based plant (currently running on naphtha). The upward rally in oil prices in 2000, pushed up DPC's power bill, putting pressure on the cash strapped MSEB. With repeated representations by MSEB, the Petroleum Ministry increased gas allocation to MSEB from 2.24 MMSCMD to 2.5 MMSCMD in January 2001.

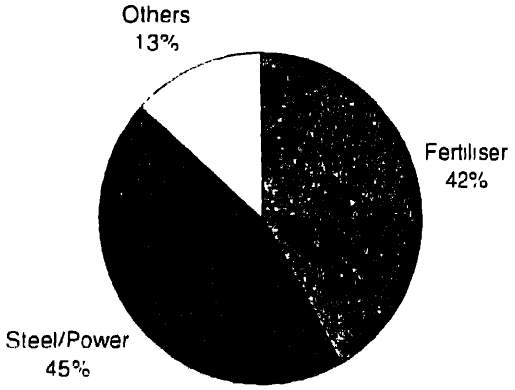
In addition, the Tata Electric Company (TEC) is operating a 180 MW gas turbine at Trombay (IIL, 2001a). TEC has tied up with Indigas for offtake of 1.2 MMTPA of LNG of the proposed 3 MMTPA LNG plant at Trombay to switch TEC's remaining 1350 MW of thermal capacity on liquid fuel to gas. These plants are being currently operated on Low Sulphur Heavy Stock (LSHS).

Fertiliser sector. Rashtriya Chemicals and Fertilisers Limited (RCF) accounts for the bulk of the gas consumed in the fertiliser manufactures urea, complex fertilizers and industrial chemicals. It has operating facilities at Thal and Trombay in Maharashtra. It is planning to put a third plant to manufacture 2250 TPD of urea at Thal (FAI, 2000). While it is currently sourcing gas from GAIL, it is facing acute shortage of gas supply at both locations. Accordingly, RCF has signed an agreement with Enron Energy Marketing Company Private Limited (EEM) for replacing the existing shortfall in GAIL's supplies, to meet additional demand arising from de-bottlenecking of their existing facilities at Thal, and the addition of third urea train at Thal. RCF's agreement with EEM envisages offtake of 1 MMTPA of LNG for their existing plants and de-bottlenecking of capacity at Thal.

Hazira

Key customers at Hazira are Krishak Bharti Co-operative's (KRIBHCO) fertiliser plant and Essar's power & integrated steel plants. Against an allocation of 6.9 MMSCMD to customers at Hazira (Figure 5.3), sales in 1999/00 averaged 5.3 MMSCMD.

Figure 5.3 Sectoral gas allocations at Hazira



Fertiliser sector. Against a capacity of 1,452 TMT of urea, actual production at KRIBHCO's 2700 TPD ammonia facility at Hazira in 1999/00 was 1,557 TMT (FAI, 2000). In addition, KRIBHCO's proposal of 1350 TPD expansion at Hazira is under consideration.

At the end of 1999/00, KRIBHCO had a cash surplus of Rs 14,200 million, earmarked for investments in Gujarat and took up a 25% stake in Gujarat State Energy General's (GSEG) gas-based 156 MW plant at Hazira (HT, 2000). The GSEG plant has already achieved financial closure and its first turbine is likely to be commissioned by the end of 2001.

KRIBHCO has also set up a new company, KRIBHCO Energy Ltd (KEL), which has plans for putting up a 615 MW gas based plant at Pipavav in Gujarat. The

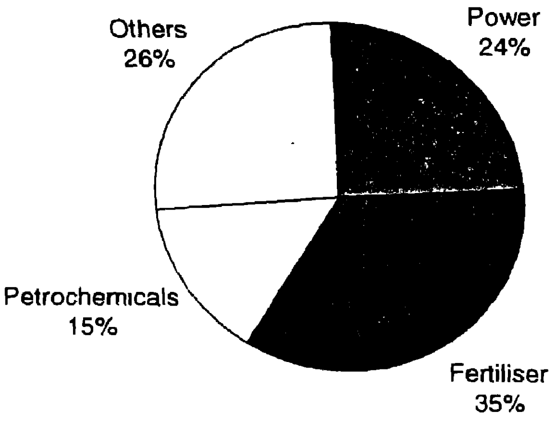
Gujarat Government has been granted an in-principle allocation of 2.25 MMSCMD of gas from the Tapti fields by the Ministry of Petroleum & Natural Gas (MoPN&G).

Iron & steel. The Essar group has an integrated mini-mill at Hazira. The plant has an installed capacity of 1.76 MMTPA of gas-based Hot Briquetted Iron (Essar, 2001). The plant draws 215 MW of power from the Group's neighbouring gas based power plant of 515 MW. Total allocation to Essar's facilities aggregate 3.11 MMSCMD. Actual gas supplies to the power plant have, however, been less than the allocation and requirements have to be bridged through naphtha. In 1999/00, Essar Power consumed 232 TMT of naphtha to meet the shortfall in gas supplies.

HBJ customers

Gas demand from the fertiliser sector leads the registered demand of the HBJ customers (Figure 5.4).

Figure 5.4 Sectoral allocations along the HBJ pipeline



Against a total allocation of 40.8 MMSCMD, gas sales to HBJ customers in 1999/00 aggregated 27.3 MMSCMD.

Fertiliser sector. Details of gas based fertiliser units along the HBJ are presented in Table 5.2. GSFC receives only a part of its requirements from the HBJ system, while the rest are met from the South Gujarat onshore gas network.

Table 5.2 Gas based fertiliser plants along the HBJ pipeline

Plant	Location	Ammonia Plant Capacity (TPD)
Gujarat State Fertilisers & Chemicals Ltd (GSFC)	Baroda, Gujarat	1350
Chambal Fertilisers & Chemicals Ltd (CFCL)	Gadepan, Rajasthan	1350
National Fertilisers Ltd (NFL)	Bijaipur, Madhya Pradesh	2700
Indian Farmers Fertilisers Co-operative (IFFCO)	Aonla, Uttar Pradesh	2700
Oswal Chemicals & Fertilisers (OCF)	Shahjahanpur, Uttar Pradesh	1350
Tata Chemicals Ltd (TCL)	Babrala, Uttar Pradesh	1350
Indo Gulf Fertilisers & Chemicals Corp (IGFCC)	Jagdishpur, Uttar Pradesh	1350

The general gas allocation for a 1350 TPD plant by the MoP&NG is 1.76 MMSCMD. In addition to the above, a second naphtha based urea train of 1350 TPD was commissioned at CFCL's plant at Gadepan in October 1999 (FAI, 2000).

Power sector. Table 5.3 lists the gas based power plants drawing gas from the HBJ pipeline system. Except for the 265 MW gas turbine owned by the Delhi Vidyut Board (DVB), all other plants are owned by the National Thermal Power Corporation (IIL, 2001a).

Table 5.3 Gas based power plants along the HBJ system

Plant	Location	Capacity (MW)
National Thermal Power Corporation	Kawas, Gujarat	645
National Thermal Power Corporation	Anta, Rajasthan	413
National Thermal Power Corporation	Auriya, Uttar Pradesh	652
National Thermal Power Corporation	Dadri, Uttar Pradesh	817
National Thermal Power Corporation	Faridabad, Haryana	450
Delhi Vidyut Board	Delhi	265

Naphtha consumption at NTPC Kawas aggregated 182 TMT in 1999/00 as there was a shortfall in supply of gas. NTPC's units at Kawas, Anta, and Auriya are slated for second stage capacity expansion of 650 MW each during the Tenth Plan (2002-2007). NTPC has signed a Memorandum of Understanding with Gujarat Pipavav LNG Ltd, the promoter of the 5 MMTPA LNG terminal at Pipavav, Gujarat, for gas supplies for its Kawas unit. Additional gas for expansions at Anta and Auriya is expected to be sourced from Petronet's 5 MMTPA LNG terminal at Dahej.

The Western onshore

The Western onshore region consists of two separate networks, the North Gujarat network and the South Gujarat network. While the North Gujarat network draws on supplies from onshore fields in Kalol, Kadi and Nawagam, the South Gujarat Network draws on the fields in Ankleshwar, Gandhar and the Cambay basin. The two networks have a combined allocation of about 11 MMSCMD, of which the

South Gujarat network accounts for about 80% of the allocation. The Western onshore sales in 1999/00 aggregated 7 MMSCMD.

Two customers on the North Gujarat network, IFFCO's 1100 TPD fertiliser plant at Kalol and Ahmedabad Electricity Company's (AEC) 40 MW gas turbine at Vatwa, account for about 65% of the total allocation on the North Gujarat network.

The power sector, with an allocation of 5.7 MMSCMD, accounts for about 60% of the total allocation in the South Gujarat network. Table 5.4 details a list of gas based power plants on the South Gujarat network.

Table 5.4 Power plants on the South Gujarat Network

Company	Location	Capacity (MW)
National Thermal Power Corporation (NTPC)	Jhanore-Gandhar	648
Gujarat Torrent Energy Corporation (GTEC)	Paguthan	655
Gujarat Industries Power Company Ltd (GIPCL)	Baroda	305
Gujarat Electricity Board (GEB)	Dhuvaran	54
Gujarat Electricity Board (GEB)	Utran	135

NTPC plans to augment the capacity at Gandhar by 655 MW during the Tenth Plan. GTEC has also received in-principle clearance from the Gujarat Government to expand the capacity at Paguthan by 655 MW. The company is in consultation with various LNG promoters in the state for annual purchases of 1.45 MMTPA of LNG (IIL, 2001b). GIPCL, also plans to put up additional 160 MW of gas based capacity at Baroda (GIDB, 2000). In addition, a proposal to raise the capacity at Dhuvaran to 100 MW is under active consideration.

There are two fertiliser units on the South Gujarat network. The Gujarat Narmada Valley Fertilisers Co Ltd has a 1,350 TPD fuel oil based plant at Bharuch (FAI, 2000). The plant uses gas only for production of methanol. The other plant is GSFC, which receives part of its allocation from the HBJ system and the remaining from the South Gujarat network.

The Krishna-Godavari (KG) Basin

Gas allocations in the KG basin aggregating 14.4 MMSCMD are more than thrice the current sales of 4.3 MMSCMD. Bulk of these (77%) have been given to power generating companies. The region currently accounts for 542 MW of gas based capacity, the details of which are presented in Table 5.5.

Table 5.5 Gas based power generating capacity in KG basin

Company	Location	Capacity (MW)
Andhra Pradesh Gas power Corporation Ltd (APGPCL)	Vijjeswaram	99
GVK Industries	Jegurupadu	235
Spectrum Power Generation Ltd	Kakinada	208

GVK industries and Spectrum have each planned capacity additions of 360 MW. LANCO's 360 MW plant at Kondapalli is already operational on naphtha. The plant has, however, been allocated 1.12 MMSCMD of gas and GAIL is constructing a 208-km pipeline to LANCO from its Tatipaka gas gathering station.

In addition, gas allocations have also been given to the 445 MW Konaseema EPS Oakwell project, the 520 MW Vemagiri project, the 360 MW Gautami Power project and the 134 MW NCC Power project.

There is only one gas based fertiliser unit in the KG basin. Nagarjuna Fertilisers & Chemicals Ltd have a 1800 TPD ammonia unit at Kakinada with an annual urea production capacity of 990 TMT. Actual production in 1999/00 was 1300 TMT (FAI, 2000).

A proposal to set up a gas based 1350 TPD plant by IFFCO at Nellore, Andhra Pradesh is under consideration by the Government.

Short term outlook for gas demand

The short-term outlook for gas demand is essentially supply driven, with project expansions being linked to gas imports. LNG imports on the west coast are expected to materialise by 2005. Additional gas from LNG terminals would cater to,

a) Current deficits of existing gas consumers, i.e., the difference between gas allocated to them and actual supplies received

b) New gas based projects

In case of the power sector, current shortfalls (in the north-western part of the country) add up to 10.3 MMSCMD. In addition, new gas based power projects, detailed in the preceding section, would require about 20.6 MMSCMD of gas. Total additional short-term gas requirements for power generation are expected to be about 30.9 MMSCMD. A detailed list of existing and potential gas based power plants is presented in Appendix 5.1.

With regards to gas demand for fertiliser production, the Planning Commission has estimated a demand-supply gap for urea of 3 MMT by 2004. The proposals under consideration include the 768 TMT capacity plants at Thal, Hazira, and Nellore (discussed in the preceding section). In addition, KRIBHCO has proposed a grass root 768 TMT urea plant at Gorakhpur in the state of Uttar Pradesh. The proposed capacity additions from these aggregate to 3.1 MMT. However, the Public Investment Board (PIB) has raised questions on the viability of the projects at Nellore and Gorakhpur as the subsidy component for these grass roots plants is likely to be quite high. The development of these two projects has therefore been put on hold.

The Oman India Fertiliser Company, a joint venture between the Oman Oil Company, KRIBHCO and IFFCO, is putting up a 1.65 MMT urea plant in Oman. The project was approved by the Indian Cabinet in January 2001. Output of the Oman project, along with that of the proposed expansions at Thal and Hazira would match the indicated deficit of 3 MMT by 2004.

The new capacities at Thal & Hazira would require about 5.1 MMSCMD of additional gas. With current shortfall for the fertiliser sector at 3.7 MMSCMD, the short term demand outlook for the fertiliser sector envisages additional gas requirements of 8.8 MMSCMD. Additional gas demand from existing naphtha/dual fuel based units (north western region only) switching to gas is minimal and has been ignored in the short term outlook. A detailed list of existing and potential gas based urea plants is presented in Appendix 5.2.

For other sectors, new capacities/projects have not been considered and the short-term outlook essentially reflects the difference between current allocations and sales. Industrial gas demand projections have been slightly moderated to reflect the difficulties in serving widespread demand and competitive fuel pricing of other industrial fuels. Short-term demand projections, based on the above mentioned, are summarised in Table 5.6.

Table 5.6 Short-term gas demand outlook (MMSCMD)

Year	Power	Fertiliser	Industry	Transport	Domestic	Total*
1999	25.0	24.4	9.1	0.1	0.7	59.4
2005	55.9	33.2	11.9	0.5	1.3	102.7

* Gas for captive use, LPG shrinkage and other non-energy uses (5.8 MMSCMD in 1999) ignored in forecasts

Long-term demand estimates under the present study reflect gas demand assessments for 2010 and beyond. For 2005, the above mentioned short term estimates figure in the long-term gas demand projections of Scenario 3 which follows.

Long-term outlook for gas demand

Conventional analyses on long-term demand forecasts rely on trend analysis. However, in the case of the Indian gas industry it has not been possible to project demand by a simple trend extrapolation as restricted gas sales do not reflect actual demand. In addition, administered prices for natural gas disassociate "perceived" demand from inter-fuel economics. Therefore, varying projections reflecting different assumptions have been made in the past. Since forecasting assumptions, which reflect prevailing outlooks on various forecasting parameters, change from time to time, a fresh look has been undertaken in this study to assess the long-term gas demand in the country. In all three scenarios have been analysed in this chapter,

Prior studies

- Scenario 1: Development of Natural Gas Masterplan" by the Bechtel Consulting-London Economics-Centre for Energy, Petroleum and Mineral Law Technology-TERI consortium in 1998.
- Scenario 2: Sub-group on Development and Utilisation of Natural Gas in "Hydrocarbon Vision 2025" in 1999.

New scenario

- Scenario 3: GDP Indexed Demand Growth (GIDG)

The chapter concludes with a comparative analysis of the three scenarios and why Scenario 3 is the preferred scenario.

Scenario 1: Natural gas masterplan

The Masterplan projections for the power sector draw upon the power demand projections under the 15th Electric Power Survey (EPS) of the CEA. The 15th EPS estimates were based on long-term trends in domestic/commercial consumer base, energisation of agricultural pumpsets, power sales to industrial consumers, railway track electrification, etc. These forecasts were used by the CEA to develop the Fourth National Power Plan which detailed the plan wise {IX (1997-2002), X (2002 - 2007) and XI (2007 - 2012) Five Year Plans} schedule for additions to power generating capacity. The Fourth National Power Plan indicated requirement of thermal capacity additions of 43527 MW, 21430 MW and 26940 MW during the IX, X and XI Five Year Plans.

The Masterplan study analysed the economics of gas use for power generation for this proposed thermal capacity addition. The imputed value for gas, the price of gas at which gas based generation is competitive to other modes/competing fuels, was assessed at 42 representative locations covering the entire country. Gas demand for power generation was assessed at different price levels, namely, below \$3/MMBtu, between \$3-\$4/MMBtu and above \$4/MMBtu. In case of fertilisers sector, the Masterplan considered fertiliser production in India uneconomical and recommended imports.

Gas prices are generally indexed to oil prices. OPEC's current pricing mechanism is likely to keep oil prices within the range of \$22/bl to \$28/bl. Given these prices, import parity gas prices in India are likely to hover around \$4/MMBtu. Gas demand estimates from the Masterplan Study at a price of $4/MMBtu are summarised in Table 5.7.

Table 5.7 Scenario 1: Gas demand projections under Natural Gas Masterplan (MMSCMD)

Year	Power	Fertiliser	Others	Total
2001	40	38	12	89
2006	73	38	12	122
2011	112	38	12	161

Scenario 2: Hydrocarbon Vision 2025

Gas demand for power generation under Hydrocarbon Vision 2025 also employ the results of the Fourth National Power Plan. The study reviewed thermal capacity additions indicated in the Fourth National Power Plan, and assessed gas demand for two scenarios, i.e., gas prices at $3/MMBtu and at $4/MMBtu. For projections beyond 2012, the long-term forecasts by NTPC on likely gas based capacity were utilised.

In case of gas use for fertiliser production, the study envisaged maximum urea imports of 2 MMT, with the balance requirements to be met from indigenous sources. Urea demand estimates were based on forecasts made by the Fertiliser Association of India for foodgrain requirements for the country.

Gas demand projections under the second scenario, i.e., at a price of $4/MMBtu is presented in Table 5.8.

Table 5.8 Scenario 2: Gas demand projections under Hydrocarbon Vision 2025(MMSCMD)

Year	Power	Fertiliser	Others	Total
2001	40	54	23	117
2006	67	66	33	166
2011	90	83	43	216
2024	153	105	64	322

Scenario 3: GDP indexed demand growth (GIDG)

Long-term projections of gas demand in Scenario 3 have been derived from the likely gas use in different sectors - power generation, fertiliser production, transport and domestic use. These forecasts are based on outlooks for growth in different sectors of the economy. Sectoral economic growth has been adjudged in terms of the growth in value added by a sector.

There have been certain structural changes in the Indian economy over the past two decades. In 1980, the Indian economy was primarily agrarian, with the primary sector (agriculture, forestry, mining) accounting for about 42% of the total Gross

Domestic Product (GDP). At the same time, the value added from the services sector accounted for only 18% of the GDP (MoF, 2001). In 1999/00, while the primary sector continued to account for the maximum share in value addition, its share in GDP had fallen radically to 27%. The fastest growth has been witnessed in value addition from the services sector, which now accounts for about 26% of the GDP. The share of value addition from the manufacturing and trade & transport sectors have also increased marginally from 22% to 25% and from 18% to 22% respectively. One of the prime reasons for these structural change have been the economic reforms ushered in 1991. There has been progressive deregulation and liberalisation of the economy ever since. The reforms have pushed the Indian economy forward at a fast pace, registering an annual growth rate of 6% since 1990.

The Finance Minister reiterated the Government's commitment to reforms through budget initiatives in the Union Budget 2001/02. Measures proposed include increased institutional credit flow to the agricultural sector, higher planned outlay on infrastructure sectors, restructuring of state electricity boards, and structural reforms like downsizing of government, widening of the tax base and a serious commitment towards privatisation. While analysts like CRISIL expect the budget initiatives to translate into a growth of 7% in the GDP in 2001/02, general expectations that the economy would be able to sustain a growth of 6% in the next few years prevail.

The long-term forecasts in this analysis are based on a 6% growth in the economy over the period 2000-2015. Assumptions on sectoral growth rates are detailed in Table 5.9.

Table 5.9 Scenario 3: Assumptions on sectoral economic growth rates: 2000-2015

Sector	Growth Rate
Agriculture	2.5%
Manufacturing	7.0%
Transport	6.0%
Services	6.5%
Gross Domestic Product	**6.0%**

Population forecasts used for this analysis reflect the estimates of the Expert Group on Population Projections (MHA, 1996). These are summarised in Table 5.10.

Table 5.10 Scenario 3: Population projections for India (Millions)

Year	Urban	Rural	Total
1998	285	686	971
2010	398	755	1153
2015	448	772	1220

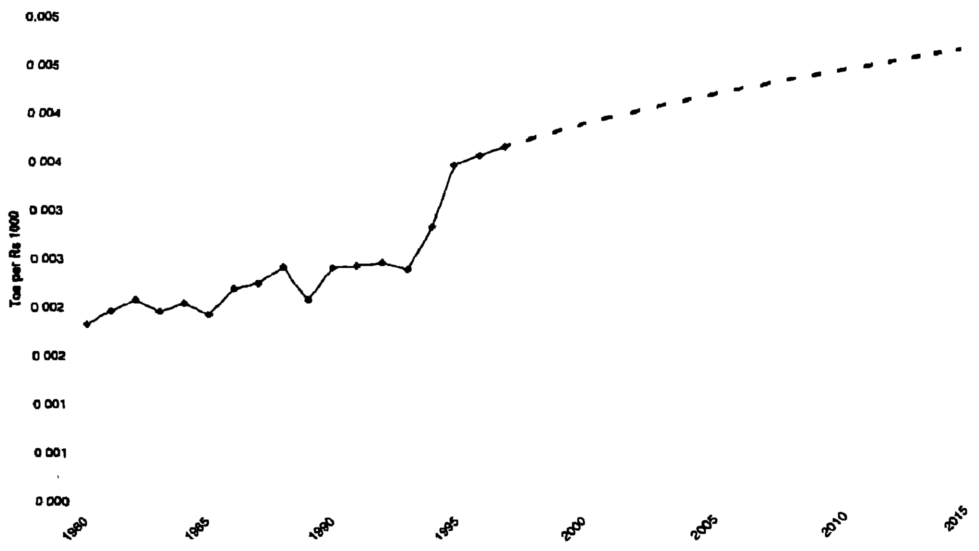
The methodology for sectoral forecasts is presented below.

Gas use for power generation

Gas demand for power generation stems from demand forecasts for power. These are adjusted for transmission & distribution (T&D) losses to arrive at generation requirements at the bus bar. Next, likely generation from other sources -nuclear, hydro, renewables and imports of power from neighbouring countries is netted out to assess requirements of thermal generation. Gas based thermal generation is then estimated as the residual generation after identifying likely thermal generation from other sources, namely, coal and oil.

Demand forecasts for power. These are based on an analysis of sectoral trends in intensity of power use, which reflects the amount of power consumed in a sector per unit of value added from that sector. Long-term trends indicate increasing intensities in most cases, albeit a declining rate. These reflect improvements in energy efficiencies and the impact of energy conservation measures. A sample plot of intensity of power use in the services/commercial sector, both actual and forecasts, is presented in Figure 5.5.

Figure 5.5 Scenario 3: Intensity of power use in the services sector - Actual & projected



While a similar pattern is observed in the agriculture sector, the industrial sector has a declining intensity of power use. The analysis suggests a shift in the structure of output from the manufacturing sector, wherein the share of energy intensive industries in the value of output is progressive declining. This is substantiated from data from the national accounts statistics, in which the share of energy intensive industries in the value output from the manufacturing sector has come down from 27% in 1980 to 21% in 1995. It is expected that these trends would extend into the forecast period as well.

Power demand from the transport sector primarily stems from the requirements of the railways. In 1999/00, the freight handled by Indian railways aggregated 308 billion-tonne kilometres (btkm) while the passenger traffic totalled 431 billion kilometres (bpkm) (MoF, 2001). Since, freight hauls depend upon the level of economic activity in the country, btkm projections are related to projections for growth in the GDP. For passenger traffic, an analysis of growth in average trip length indicated an annual growth rate of 3% since 1981. The same is used for the forecast period. Average trip rates are assumed to grow in proportion to the GDP. The penetration of electric locomotives, both in passenger traffic and freight traffic, is assumed to increase from current levels by 10% by 2015.

Power demand projections in the residential sector are based on a cross-sectional analysis of power consumption in the residential sector across countries at different levels of development. Per capita consumption of power was regressed against per capita income levels, used as a proxy variable to assess development levels. Per capita consumption forecasts are based on income projections. In addition, the proportion of rural households using electricity as a primary source for lighting is assumed to increase from the current 40% (NSSO, 1997) to 60% by 2015.

Required availability at the busbar. Generation requirements at the busbar are estimated from power demand projections adjusted for T&D losses. Reported T&D losses for 1998/99aggregated to 23.2% (PC, 2000). However, actual T&D losses are much higher. Reassessment of T&D losses in the states of Andhra Pradesh, Haryana and Uttar Pradesh revealed actual T&D losses at 51%, 40% and 42% against reported losses of 25%, 32% and 27% respectively (TERI, 2000). The forecasts assume a progressive decline in T&D losses to 20% by 2015. Power demand projections and estimates of required availability at the busbar are summarised in Table 5.11.

Table 5.11 Scenario 3: Power demand projections and required availability at the busbar (MkWh)

Year	Power Demand	Required Availability At the Busbar
1998	303292	417016
2010	701962	886262
2015	925801	1162330

Generation from other sources. Estimates of likely generation from other sources are primarily derived from proposed additions to generating capacity as estimated by the Central Electricity Authority (CEA, 1999). CEA estimates on capacity additions are indicated plan wise, i.e., by the end of the IX (2002), X (2007) and XI (2012) Five Year Plans. However, generally slippages are observed in most projects and target capacity additions are seldom realised in planned time frames. The mid-term appraisal of the IX Plan estimates that only 60% of the original capacity addition target would be feasible in the IX plan (PC, 2001). Accordingly, in this analysis, CEA estimates of likely capacity addition are deferred by three years, i.e., indicated capacity addition by 2007 would be realised by 2010 and that planned for 2012, by 2015. Assumptions on mode wise likely capacity additions till 2015 are summarised in Table 5.12.

Table 5.12 Scenario 3: Mode wise capacity addition from non-fossil fuel sources (MW)

Mode	1999	2010	2015
Hydro	22443	45037	58503
Nuclear	2225	7160	12100
Renewables	1615	11000	16500

In addition, imports of electricity from Nepal and Bhutan have also been considered. Nepal has an estimated hydro potential of 83,000 MW, while the same for Bhutan is 21,000 MW. Planned and proposed capacity additions in Nepal target harnessing 30% (24,863 MW) of this potential. However, given the current installed capacity 262 MW, this target seems ambitious and in this analysis it is assumed that only 15% of the proposed target would be realised by 2015. Domestic load forecasts by 2015, as estimated by the Nepal Electricity Authority, aggregate 1,165 MW, indicating that the export potential in Nepal is likely to be about 11,285 MW.

Likewise, planned & proposed projects in Bhutan also target harnessing 30% of their potential. Again, anticipated realisation in this analysis is limited to 15% of the potential, which renders export capabilities of 982 MW by 2015.

Gas based generation. Estimates of required thermal generation are derived by netting out generation from non-fossil fuel sources from the required availability at the busbar. At a plant load factor (PLF) of 68.5% (used by CEA for its planning exercises), the required thermal capacity works out to be 118,531 MW and 139,567 MW by 2010 and 2015 respectively.

The current share of coal based capacity in total thermal capacity is 85%. However, a review of trends in coal production in the country indicates signs of stagnation in the coal industry. While coal production grew at a healthy 5% during the first half of the last decade (1990-95), the growth came down to a mere 2%

during the period 1995-99. Although productivity in Indian coal mines has improved considerably over time, it is still less than one-twentieth that in Germany and the US (TERI, 2000). Factors contributing towards delays in opening of new mines include environmental clearances, labour problems, problems in land acquisition, rehabilitation of ousters, etc. If current trends persist, coal production by 2015 may well be only about 450 MMT. In 1998/99, of the total coal production of 289 MMT in the country, coal use for power generation accounted for 70% of the total production. Assuming a similar share for other sectors in 2015 as well, domestic coal availability for power generation in 2015 is likely to be about 315 MMT only.

Coal production is primarily restricted to the eastern region of the country. Rail transport capacity for widespread distribution of coal throughout the country from the eastern region is likely to be a serious bottleneck in the future. In such a scenario, coal imports at coastal and near coastal areas, far away from the eastern region, seem imminent. Non-coking coal imports aggregated to about 6 MMT in 1998/99. It is assumed that these are likely to increase to about 20 MMT by 2010. Further increase in non-coking coal imports is assumed to be more rapid, with imports estimated at about 40 MMT by 2015.

Thus, total coal availability, domestic and imported, for power generation in 2010 is estimated to be 300 MMT, expected to rise to 355 MMT by 2015. Deferring CEA estimates of likely oil based generating capacity in 2007 by three years, the oil based generating capacity in 2010 is estimated to be 9,631 MW. There are no plans for additional oil based capacity beyond the X plan. The residual thermal capacity would have to be gas based. Likely gas based thermal capacities and gas requirements for the same are summarised in Table 5.13.

Table 5.13 Scenario 3: Gas based generating capacity and associated gas demand for power generation

Year	Gas based generating capacity (MW)	Gas requirements for power generation (MMSCMD)
1999	9091	25.0
2005*	20001	55.9
2010	24800	69.3
2015	28202	78.8

* Short-term estimates (supply driven)

Gas use for fertiliser production

Though the share of the agriculture sector in the total value added in the economy has been declining over the last two decades, it still dominates the Indian economy. Foodgrain production in the country has quadrupled since 1951 to 206 MMT in

1999/00. Growth in foodgrain production has been achieved through introduction of high yielding varieties, increased land area under irrigation, and promoting use of fertilisers and pesticides.

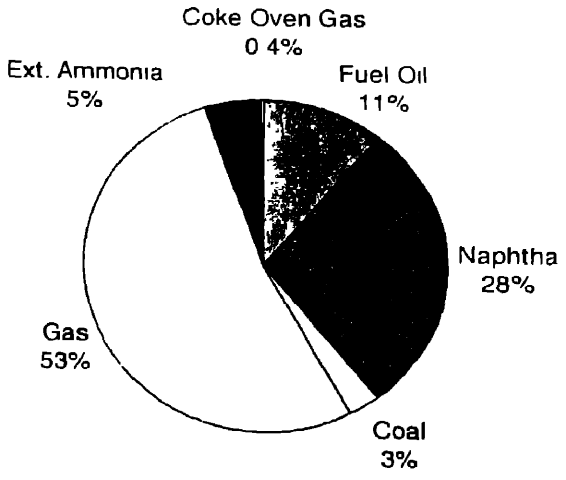
Urea demand. While urea consumption in 1998/99 was about 20 MMT, fertiliser use in India remains low as compared to other countries in the world. Fertiliser consumption in India in 1998/99 at 99 kgs/hectare contrasts poorly against that in other countries like UK (330 kgs/hectare) and China (257 kgs/hectare).

The fertiliser application intensity, i.e., fertiliser consumption per unit of food grain production, has however been rising steadily, albeit at a declining rate. Given the relatively low use of fertilisers in India, a similar trend is expected to hold in the forecast period as well.

Fertiliser demand projections are related to foodgrain production in the country. Estimates of foodgrain production, in turn, are drawn from projected growth in value addition from the agriculture sector. By extrapolating past trends, fertiliser consumption per tonne of food grain production is expected to rise from 68 kgs in 1998 to 82 kgs by 2015. Assuming, that the current N:P:K (Nitrogen, Phosphorous, Potassium) ratio would hold in the future as well, urea demand in 2015 is estimated at 29.5 MMT.

Feedstock considerations. The current installed capacity of nitrogenous fertilisers in the country aggregates 11.07 MMT. Bulk of this capacity is gas based (Figure 5.6).

Figure 5.6 Installed capacity of nitrogenous fertilisers by feedstock use



Until recently, the fertiliser industry in India was operating under the Retention Pricing System (RPS). Under the RPS, fertiliser units received 12% post-tax return on their net worth. Plants were compensated for their feedstock costs, operating costs and capital costs. The RPS being essentially a cost-plus scheme provided little incentives for units to target cost efficiency.

At the same time, urea prices are controlled by the Government and kept at a low level. While current urea prices are pegged at Rs 4,600/MT, the average cost of production is even higher than the long-run marginal cost of Rs 6,500/MT (MoF, 2001). The difference between farm-gate urea prices and the retention prices paid to fertiliser plants accrues as subsidy. Fertiliser subsidy for 1999/00 was as high as Rs 132, 440 million.

The second report of the Expenditure Reforms Committee (ERC) recognised the deficiencies of the current system and called for dismantling of the RPS scheme. The Committee, however, took note of the fact that sudden decontrol of the urea industry would be counter productive as most units would have to be shut down given that their variable costs itself exceed the import parity price of urea. The resultant increase in urea imports would push urea prices in international markets to such levels that the subsidy outgo would be even higher.

The Committee recommended the use of natural gas for fertiliser production. However, on account of limited availability of domestic gas, the Committee recommended a phased system of decontrol with compensation for use of other feedstocks. The phased decontrol was initiated with the discontinuation of the RPS in the Union Budget 2001/2002. The new system employs the Group Concession Scheme, details of which have been presented in the previous chapter.

Gas demand. Gas demand for urea production in this analysis is based on ERC's recommendations favouring gas use for urea production. With issues of fo[illegible] security in mind, fertiliser imports are assumed to be low to a maximum of 10% of the total urea demand. All indigenous urea production is assumed to be gas based by 2010. Gas requirements for urea production are estimated on the basis of energy requirements of 5.4 Gcal/tonne of urea (Rao, 1998). Estimates of likely gas requirements for urea production are presented in Table 5.14.

Table 5.14 Scenario 3: Gas demand for urea production (MMSCMD)

Year	Gas Demand
1999	24.4
2005*	33.2
2010	40.2
2015	46.3

* Short-term estimates (supply driven)

Gas use by industries

Over the past decade gas consumption by industries has increased rapidly, registering an annual growth rate of 12.5%. Bulk of the gas demand is from the following industries: Iron & steel, glass, ceramics, and textiles.

Given the diverse spread in usage, projections for industrial gas demand are based on the aggregate intensity of gas use in the industrial sector, i.e., the amount of gas consumed per unit of value added from the manufacturing sector. Past trends indicate a rapidly rising industrial gas intensity. However, as mentioned earlier, the share of energy intensive industries in the value of output from the manufacturing sector has been declining over the past couple of decades. With the expectation that such a trend would persist in the future as well, growth in intensity for the projection period is suitable moderated to reflect the lower share of energy intensive industries in the value added from the manufacturing sector.

Industrial gas demand projections, based on the revised intensity estimates are presented in Table 5.15.

Table 5.15 Scenario 3: Industrial gas demand (MMSCMD)

Year	*Gas Demand*
1999	9.1
2005*	11.9
2010	15.6
2015	21.9

* Short-term estimates (supply driven)

Gas use for transport

Current scenario. Natural gas finds usage in the transport sector in the form of Compressed Natural Gas (CNG). In India, CNG was introduced by Gujarat Gas Company in the city of Surat in Gujarat in 1993. Currently, the city has 671 cars running on CNG (MoP&NG, 2000). Gujarat Gas has also initiated CNG use in the city of Ankleshwar in Gujarat, though only 93 cars run on CNG. CNG is being marketed in a big way in Mumbai in Maharashtra by Mahanagar Gas Ltd (MGL), a joint venture between the Gas Authority of India Ltd (GAIL) and British Gas. MGL has 12,500 cars, primarily representing 25% of the city's taxi fleet running on CNG. IN addition, MGL has also converted 10 buses of the public fleet to CNG. MGL is also undertaking trial runs on three wheeler transport vehicles – autorickshaws.

In Delhi, CNG is being marketed by Indraprastha Gas Ltd (IGL). IGL currently has about 9,000 cars, 6,000 autorickshaws and 155 buses running on CNG. On account of rising air pollution in the city, the Supreme Court had directed

- The replacement of all pre 1990 autorickshaws and taxis with new vehicles on clean fuels by 31st March 2000

- No 8 year old bus to ply, except for those on CNG or other clean fuels by 31st March 2000
- The entire city bus fleet to be converted to a single fuel mode i.e. CNG by 31st March 2001

The Delhi Government, however, has been unable to comply with the Supreme Court directives to convert the 12,000 strong city bus fleet to CNG with problems from suppliers and retrofitting. On 25th March 2001, the Supreme Court allowed conditional extension of the deadline for six months subject to the condition that only those operators would be able to ply buses who place firm orders for conversion to CNG by 30th September 2001.

Forecasts. CNG sales in 1999/00 aggregated 30 MMCM, with Mumbai accounting for about 80% of the total sales. Long-term forecasts for CNG use are based on projections for urban travel demand. Surveys undertaken in selected cities indicated an average motorised urban trip rate of 0.84 (number of trips/capita/day), while the maximum trip rate was observed as 1.49 (RITES, 1995). The average urban trip length in the same worked out to be 5.5 kms, while the maximum trip length was estimated as 9.77 kms.

The increase in travel demand during the projection period, would be reflected through the increase in trip rates, trip lengths and urban population. For the projections, a 25% increase is assumed over the current average trip rates and trip lengths by 2015.

Based on the registered vehicle populations (MoST, 1997) and the number of vehicles running on CNG, the current penetration of CNG in passenger three wheelers, buses and cars is estimated to be 0.5%. Given the impetus to shift towards clean fuels with rising air pollution in urban cities, a 250% increase in penetration of CNG vehicles is assumed by 2015.

Based on the modal splits in urban transport demand from the above and the fuel efficiencies of CNG vehicles, projections for gas demand from the transport sector are presented in Table 5.16.

Table 5.16 Scenario 3: Gas demand from the transport sector (MMSCMD)

Year	Gas Demand
1999	0.1
2005*	0.5
2010	0.7
2015	1.0

* Short-term estimates (supply driven)

Domestic gas use

Current Scenario. Like CNG, piped gas supplies are restricted to a few cities in Gujarat, Mumbai and Delhi. In Gujarat, two companies are engaged in the business of gas distribution. The Gujarat Gas Company has a 1000 km network spanning the cities of Surat, Ankaleshwar and Bharuch. The company has recently commissioned its 70-km high pressure pipeline from Hazira to Ankaleshwar to boost gas supplies in the region. It has a customer base of over 100,000 customers. The Baroda Municipal Corporation, responsible for gas distribution in the city of Vadodara, has over 55,000 residential customers.

In Mumbai, gas is being distributed by MGL, which has over 12,000 domestic customers. MGL plans to enlarge its distribution network to cover over 600,000 customers through a 2,700 km network. In Delhi, IGL has set up a distribution network of 50-kms in South and Central Delhi, covering 2,500 customers. In addition, IGL plans to cover another 5,800 customers in areas where its projects are under execution.

Projections. Based on the current sales of LPG, Kerosene and piped gas, it is estimated that piped gas accounts for only 3% of the total domestic urban commercial energy supplies. For this analysis, it is assumed that the share of piped gas supplies would double to 6% by 2015.

An analysis of past sales of the above mentioned fuels, adjusted for their respective efficiencies of utilisation, indicated that the net heat value supplied to urban customers has increased from 186 kcal/capita/day in 1980 to a current level of 410 kcal/capita/day, registering an annual growth rate of 5%. It is assumed that net heat value requirements in the forecast period would increase at a relatively lower rate of 3.5%. These in conjunction with projections for urban population and the likely share of piped gas supply in the total urban domestic energy basket, is used to assess the likely gas requirements for the domestic sector (Table 5.17).

Table 5.17 Scenario 3: Gas demand from the domestic sector (MMSCMD)

Year	Gas Demand
1998	0.7
2005*	1.3
2010	1.7
2015	2.7

* Short-term estimates (supply driven)

Aggregate gas demand

The sectoral gas demand projections presented in the preceding sections have been summarised in Table 5.18.

Table 5.18 Scenario 3: Gas demand projections summary (MMSCMD)

Year	Power	Fertiliser	Industry	Transport	Domestic	Total#
1999	25.0	24.4	9.1	0.1	0.7	59.4
2005*	55.9	33.2	11.9	0.5	1.3	102.7
2010	69.3	40.3	15.6	0.7	1.7	127.6
2015	78.8	46.3	21.9	1.0	2.7	150.8
CARG	7.4%	4.1%	5.7%	15.4%	8.9%	6.0%

* Short-term estimates (supply driven)

# Gas for captive use, LPG shrinkage and other non-energy uses (5.8 MMSCMD in 1999) ignored in forecasts

Results indicate substantial changes in the demand structure over the next 15 years. The share of gas demand for power generation notches up to 52%, as against the current 40%, while that for fertiliser is expected to come down to about 30%. Gas demand in the transport sector, in the form of CNG, rises rapidly. However, it still constitutes less than 1% of the total demand by 2015.

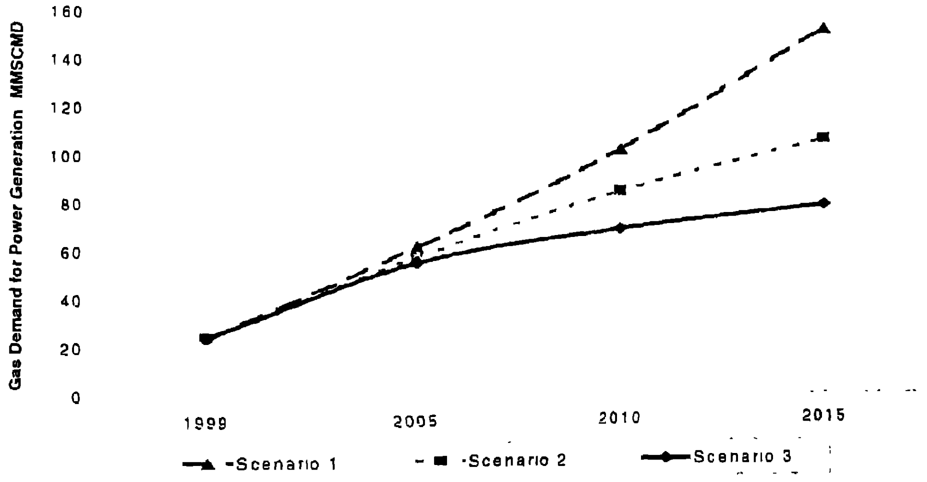
Gas demand projections: comparative analysis

There are considerable variations in estimates for gas demand projections in prior studies and those assessed in the present analysis. These variations primarily stem from differences in assumptions used for forecasts. Also while Scenario 1 gas demand for power is based on imputed values calculated at as many as 42 locations, imputed values determined at 5 locations in Chapter 4 have been used broadly in Scenario 3. A sector-wise comparison is presented below.

Estimates on gas use in power generation

Estimates of gas demand for power generation in 2015 vary between 79 MMSCMD to 152 MMSCMD (Figure 5.7).

Figure 5.7 Comparative Gas demand projections for power generation



While details of the methodologies adopted in different studies have been presented earlier, the key differences in the same are summarised below in Table 5.19. Gas demand projections under the Scenario 3 (GIDG) set the lower-bound on the forecasts. The successive reductions in gas demand estimates under the three scenarios essentially reflect revised power demand estimates for the country. Scenario 1 (Masterplan study) draws upon the 15th EPS power demand estimates. Scenario 2 (Hydrocarbon Vision) also employs the same, albeit with downward revisions in power demand estimates, the impact of which is visible in the reduction in gas demand.

Scenario 3 reflects the latest assessment of power demand. In addition, the scenario also allows for coal imports. Imputed values in the preceding chapter indicate that imported coal is competitive at locations distant from coal bearing areas and coastal areas. Imported coal at these locations, reduces the share of gas based generation in the overall thermal generation, leading to reduced gas requirements.

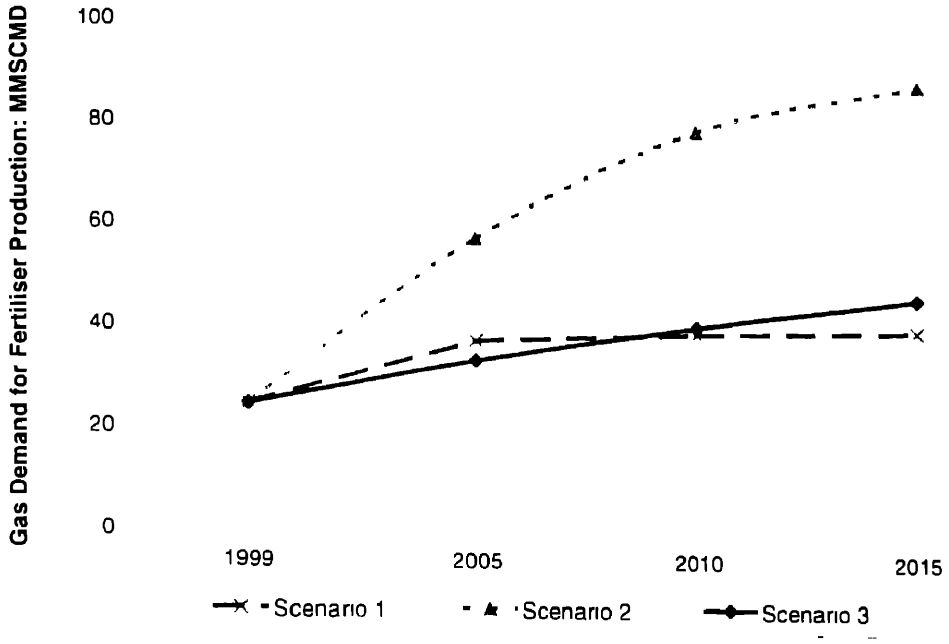
Table 5.19 Comparative analysis: Assumptions on forecasts for gas demand for power generation

Parameter	Scenario 1 (Masterplan)	Scenario 2 (Hydrocarbon Vision)	Scenario 3 (GIDG)
Power demand	15th EPS projections	Till 2012: 15th EPS projections Beyond 2012: Extrapolation of trends in elasticity & GDP growth of 7%	Linked to GDP growth of 6%
- Sectoral forecasts	Trend extrapolation: • Domestic/commercial - Consumers • Agriculture - Energisation of pumpsets • Industries - Sales • Traction - Track electrification	Trend extrapolation: • Domestic/commercial - Consumers • Agriculture - Energisation of pumpsets • Industries - Sales • Traction - Track electrification	Domestic. Trend extrapolation of per-capita consumption Agriculture/Industries/Transport: Extrapolation of trends in sectoral intensities
Thermal capacity	Fourth National Power Plan estimates by CEA	Fourth National Power Plan estimates by CEA	Load requirements less likely imports, renewables, nuclear and hydro
Gas based capacity	Likely additions at a gas price of \$4/MMBtu	Likely additions at a gas price of \$4/MMBtu	Residual share after netting out coal & oil based thermal
	Ninth plan: 2725 MW Tenth Plan: 8666 MW Eleventh Plan: 10284 MW	Ninth plan: 3745 MW Tenth Plan: 6883 MW Eleventh Plan: 6108 MW	Coal: Domestic coal production restricted to 450 MT, with coal imports at 40 MMT Oil: Proposed additions considered by CEA

Estimates on gas use in fertiliser production

Estimates of gas demand projections for urea production in different studies are summarised in Figure 5.8

Figure 5.8 Comparative analysis: Gas demand projections for urea production



Scenario 1 (Masterplan) did not favour indigenous fertiliser production and recommended imports of urea. Gas demand therefore remains flat after 2005. However, given issues of food security, such a policy does not hold merit. Moreover, if India were to go for large bulk imports, the international prices of urea would shoot up leading to heavy foreign exchange outflows.

Assumptions on gas use for urea production in Scenario 2 (Hydrocarbon Vision) and those under Scenario 3 (GIDC) are presented in Table in 5.21. Estimates on gas requirements for urea production under Scenario 2 exceed those under Scenario 3. The gap emerges from differences in assessments of gas based urea capacity. Fertiliser requirements under Scenario 2 are estimated to increase by an additional 20 MMT by 2017. As India is self-sufficient in foodgrain production at present and as fertiliser production in the country has increased by only 11 MMT over the last two decades, an additional requirement of 20 MMT of fertilisers by 2017 is unlikely. Further, while not explicitly stated, the computed specific energy consumption per ton of urea production under Scenario 2 appears to be substantially higher than the normative 5.4 Gcal/Ton of urea used in Scenario 3.

Table 5.20 Comparative analysis: Assumptions on forecasts for gas demand for fertiliser production

Parameter	Scenario 2 (Hydrocarbon Vision)	Scenario 3 (GIDG)
Food grains production	FAI estimates	Linked to growth in value addition from the Agriculture sector at 2.5% p.a.
Fertiliser requirements	FAI estimates	Extrapolation of trends in fertiliser application intensity
Fertiliser Imports	Annual imports of 2 MMT	10% of demand
Gas based capacity & associated gas demand	Till 2001/02 - Current shortfall of gas based units - Requirements of dual fuel facilities - Conversion of naphtha based plants - Additional capacity at Thal, Hazira, Nellore and Gorakhpur Beyond 2001/02 - 80% of required capacity	Based on ERC recommendations favouring gas use - Entire domestic production beyond 2007 gas based

Estimates of gas use in industries

Gas requirements as industrial fuel aggregate to about 15% of the total demand under Scenario 3 (GIDG). A direct comparison of industrial gas requirements is not possible as Scenario 1 (Masterplan) examines gas use in sponge iron units only and concludes that it is uneconomical on account of low imputed values, while Scenario 2 (Hydrocarbon Vision) clubs industrial requirements with all non-power and non-fertiliser uses at 20% of the total demand.

There is a wide range of competing fuels in the industrial category, viz., coal, fuel oil, LPG, etc. with imputed values for gas ranging from $1.54/MMBtu to as high as $11.50/MMBtu. For sectors where process requirements dictate fuel choices, inter-fuel economics would not have a significant impact. Gas is the preferred fuel in a host of other sectors such as ceramics, glass, textiles, etc. where controlled process heating requirements are imperative. In other cases while gas is not competitive against domestic and imported coal on the basis of calorific values alone, Chapter 4 provides other reasons why gas may be preferred. Further, gas is very competitive versus fuel oil and LPG and is likely to replace these fuels once it is more freely available.

Preferred gas demand scenario

The preceding analysis indicates that Scenario 3 represents the most likely demands for gas in the two key sectors, namely, power generation and fertiliser production. Further, unlike Scenario 1 and 2, wherein gas requirements for industrial, domestic and transport purposes are treated as residual demand, Scenario 3 offers a detailed framework for assessing the same.

Considering that domestic coal is competitive for power generation in the eastern part of the country, it may preclude gas use in the region, depressing gas demand projections indicated in Scenario 3, unless gas imports via pipeline fructify from Bangladesh. On the other hand, gas demand for fertiliser production may turn out to be higher than indicated in Scenario 3 as additional imported gas availability will allow existing naphtha based plants to switch to gas. A detailed analysis, however, is beyond the scope of the present study and Scenario 3 represents the preferred demand projections for gas (reproduced in Table 5.21) in this study and has been used to determine the supply/demand balances and import requirements in the following chapter.

Table 5.21 Preferred gas demand projections(MMSCMD)

Year	Power	Fertiliser	Industry	Transport	Domestic	Total#
1999	25.0	24.4	9.1	0.1	0.7	59.4
2005*	55.9	33.2	11.9	0.5	1.3	102.7
2010	69.3	40.3	15.6	0.7	1.7	127.6
2015	78.8	46.3	21.9	1.0	2.7	150.8
CARG	7.4%	4.1%	5.7%	15.4%	8.9%	6.0%

* Short-term estimates (supply driven)

Gas for captive use, LPG shrinkage and other non-energy uses (5.8 MMSCMD in 1999) ignored in forecasts

Appendix 5.1

Existing and potential gas based power plants

Promoter	*Location*	*Capacity (MW)*
Existing gas based plants		
Ahmedabad Electricity Company	Vatwa, Gujarat	120.0
Andhra Pradesh Gas Power Corporation Ltd	Vijjeswaram, Andhra Pradesh	99.0
Assam State Electricity Board	Lakwa, Assam	120.0
Assam State Electricity Board	Mobile GTs, Assam	18.9
Assam State Electricity Board	Namrup, Assam	103.5
Delhi Vidyut Board	Delhi	265.0
Gujarat Electricity Board	Dhuvaran, Gujarat	54.0
Gujarat Electricity Board	Utran, Gujarat	135.0
Gujarat Industries Power Company Ltd	Baroda, Gujarat	305
Gujarat Torrent Energy Corporation	Paguthan, Gujarat	655.0
GVK Industries	Jegurrupadu, Andhra Pradesh	235.0
Maharashtra State Electricity Board	Uran, Maharashtra	912.0
National Thermal Power Corporation	Anta, Rajasthan	413.0
National Thermal Power Corporation	Auriya, Uttar Pradesh	652.0
National Thermal Power Corporation	Dadri, Uttar Pradesh	817.0
National Thermal Power Corporation	Faridabad, Haryana	450.0
National Thermal Power Corporation	Jhanore, Gujarat	648.0
National Thermal Power Corporation	Kawas, Gujarat	645.0
North Eastern Electric Power Corporation	Kathalguri, Assam	291.0
Spectrum Power Generation Ltd	Kakinada, Andhra Pradesh	208.0
Tata Electric Company	Trombay, Maharashtra	180.0
Tripura State Electricity Department	Baramura, Tripura	10.0
Tripura State Electricity Department	Rokhia, Tripura	40.0
Total		**7376.4**
Potential gas based plants		
Tata Electric Company	Trombay, Maharashtra	1350.0
Krishak Bharti Co-operative	Pipavav, Gujarat	615.0
Dabhol Power Company (Phase I)	Dabhol, Maharshtra	726.0
National Thermal Power Corporation	Anta, Rajasthan	650.0
National Thermal Power Corporation	Auriya, Uttar Pradesh	650.0
National Thermal Power Corporation	Jhanore, Gujarat	655.0
National Thermal Power Corporation	Kawas, Gujarat	650.0
Gujarat Electricity Board	Dhuvaran, Gujarat	46.0
Gujarat Torrent Energy Corporation	Paguthan, Gujarat	655.0
Gujarat Industries Power Company Ltd	Baroda, Gujarat	160.0
GVK Industries	Jegurrupadu, Andhra Pradesh	360.0
Spectrum Power Generation Ltd	Kakinada, Andhra Pradesh	360.0
LANCO Kondapalli Power Ltd	Kondapalli, Andhra Pradesh	360.0
Konaseema EPS Oakwell Power Ltd	Konaseema, Andhra Pradesh	445.0
Vemagiri Power Generation Ltd	Vemagiri, Andhra Pradesh	520.0
Gautami Power Ltd	Peddapuram, Andhra Pradesh	360.0
NCC Power Corporation Ltd	Bhimavaram, Andhra Pradesh	134.0
BSES, Andhra Power Ltd	Peddapuram, Andhra Pradesh	200.0
Total		**8896.0**
Grand Total		**16272.4**

Appendix 5.2

Existing and potential gas based urea plants

Promoter	*Location*	*Capacity (TMT)*
Existing gas based urea plants		
Chambal Fertilisers & Chemicals Ltd	Gadepan, Rajasthan	742.5
Gujarat State Fertilisers & Chemicals Ltd	Baroda, Gujarat	367.2
Hindustan Fertiliser Corporation	Namrup, Assam	520.0
Indian Farmers Fertilisers Co-operative	Aonla, Uttar Pradesh	1452.0
Indian Farmers Fertilisers Co-operative	Kalol, Gujarat	546.0
Indo Gulf Fertilisers & Chemicals Corporation	Jagdishpur, Uttar Pradesh	726.0
Krishak Bharti Co-operative	Hazira, Gujarat	1452.0
Nagarjuna Fertilisers and Chemicals Ltd	Kaiknada, Andhra Pradesh	495.0
National Fertilisers Ltd	Bijaipur, Madhya Pradesh	1452.0
Oswal Chemicals & Fertilisers	Shahjahanpur, Uttar Pradesh	726.0
Rashtriya Chemicals and Fertilisers Ltd	Thal, Maharashtra	1485.0
Rashtriya Chemicals and Fertilisers Ltd	Trombay, Maharashtra	429.0
Tata Chemicals Ltd	Babrala, Uttar Pradesh	742.5
Total		**11135.2**
Potential gas based urea plants		
Indian Farmers Fertilisers Co-operative	Nellore, Andhra Pradesh	768.0
Krishak Bharti Co-operative	Gorakhpur, Uttar Pradesh	768.0
Krishak Bharti Co-operative	Hazira, Gujarat	768.0
Rashtriya Chemicals and Fertilisers Ltd	Thal, Maharashtra	768.0
Total		**3072.0**
Potential naphtha to gas conversions		
Fertilisers and Chemicals Travencore Ltd	Cochin, Kerala	330.0
Indian Farmers Fertilisers Co-operative	Phulpur, Uttar Pradesh	1221.0
Madras Fertilisers Ltd	Chennai, Tamil Nadu	242.4
Mangalore Chemicals & Fertilisers Ltd	Mangalore, Karnataka	340.0
Shriram Fertilisers and Chemicals	Kota, Rajasthan	330.0
Southern Petrochemicals Industries Corporation Ltd	Tuticorin, Tamil Nadu	512.0
Zuari Agro Chemicals Ltd	Goa	280.5
Total		**3255.9**
Grand Total		**17463.1**

6

Domestic gas supply and supply-demand projections

Indigenous gas availability

Sedimentary basins in India

Sedimentary basins in India are spread over 1.39 million sq. km onshore and 0.40 million sq. km offshore. An additional 1.35 million sq. km are in deep waters.

The major basins are found along the east and west coasts, through the Assam fold belt, onshore Gujarat, Rajasthan, the Ganges valley, Bengal, and the Vindhyan and Deccan synclines in central west India. Other small basins are found scattered across the sub-continent. Only some 33% of the sedimentary area has been explored. However, the explored area includes all the areas which are presently considered to be geographically most prospective.

The various basins have been categorised according to prospectivity. Category I consists of producing basins, while Categories II to IV are basins with reducing prospectivity. The Category I basins comprise:

- Cambay basin, Gujarat
- Bombay offshore
- Cauvery basin
- Krishna-Godavari basin
- Assam shelf/Assam Arakan fold belt

Early E&P activities during the 1960s and 1970s were concentrated in Category I basins but since the 1980's efforts were focussed upon select unexplored areas in Category II basins and in offshore shallow water basins. The main sedimentary basins are shown in Figure 6.1.

Current reserves

Estimates of gas reserves based on figures from the Ministry of Petroleum and Natural Gas (MoPNG) indicate that the reserves reached 736 BCM in 1992 but declined to 648 BCM by 1999 (Table 6.1).

Figure 6.1 Sedimentary basins of India

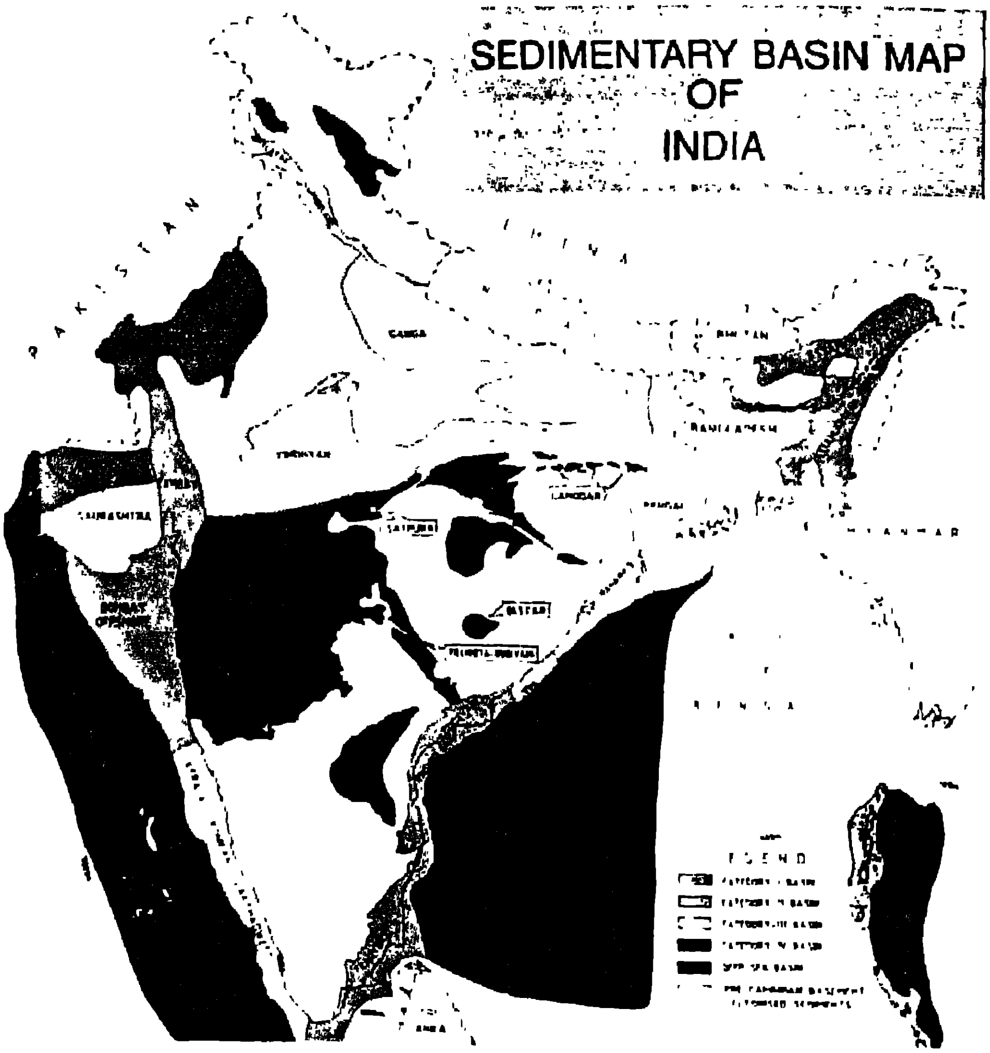


Table 6.1 State-wise proven and balance recoverable reserves of natural gas: 1970 to 1999

Natural gas reserves (BCM)	1979/80	1984/5	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Onshore												
Gujarat	16.4	21.9	92.6	93.4	94	92.9	92.1	89.9	88.0	86.5	84.2	-
Assam	63.5*	87.7*	135.5*	151.7*	160.5*	156.1*	156.2*	159.2*	173.8*	182.5*	187.7*	-
Rajasthan	0.4	0.5	1.0	1.2	1.3	3.8	3.8	4.1	4.5	4.5	4.4	-
Total Onshore	80.3	110.0	229.1	246.3	255.7	252.8	252.1	253.2	266.2	273.8	276.4	279
Offshore												
Western offshore	271.0	368.6	457.4#	483.5#	479.8#	465.1#	454.6#	406.5#	377.2#	418.0#	398.0#	369#
Total	351.3	478.7	686.5	729.8	735.6	717.9	706.7	659.7	643.3	692.1	674.8	648

* includes natural gas onshore reserves in Tripura, Nagaland, Tamil Nadu, Arunachal Pradesh and Andhra Pradesh

includes natural gas offshore reserves in Andhra Pradesh, Gujarat, Tamil Nadu and Andaman & Nicobar islands

Source: TERI Yearbook 2000/2001

Bulk of the proven reserves (>60%) are located in the Western Offshore region, the remainder mostly located in North East India (24%) and Gujarat (13%). The reserves to production ratio is 23.5. However, the effective ratio is closer to 17 since a large portion of the gas is contained in the gas caps in the oilfields, which cannot be produced until they are depleted of oil.

Growth in reserves

From a level of 185 BCM in 1975, the recoverable gas reserves in India kept growing until the year 1992. The growth was faster from 1975 to 1980 when gas reserves were added at a much greater rate than actual gas production. The net addition to gas reserves continued through the mid 1980's at a lower rate and increased through to 1992 to reach a quantum of 736 BCM. The period 1986 to 1990 saw significant proving-up of fields with net additions to the reserves, and despite a near doubling of gas production in the same period.

Since 1992, there has been a net depletion of the gas reserves to 648 BCM in 1999 (Table 6.2). The decline has been mainly due to lack of discovery of new oil and gas fields by the Indian public sector companies and their existing fields now facing a declining gas production trend.

Table 6.2 Reserve replacement ratio and life of reserves of natural gas: 1975 to 1998/9

Year	Recoverable reserves (BCM)	Net addition/depletion (BCM)	Production (BCM)	Gross addition to recoverable reserves (BCM)	Reserves replacement ratio*	Life of reserves (yrs current prodn.)
1975	185	97	2.3	99.3	43.2	80.4
1976	339	43	2.4	45.4	18.9	95.0
1977	266	38	2.7	40.7	15.1	98.5
1978	344	78	2.8	80.8	28.9	122.9
1979	352	8	3.1	11.1	3.6	113.6
1980	411	59	2.1	61.1	29.1	195.7
1981	420	9	3.5	12.5	3.6	120.0
1982	475	55	4.7	59.7	12.7	101.1
1983	478	3	5.8	8.8	1.5	82.4
1984	479	1	6.6	7.8	1.2	70.4
1985	497	18	7.9	25.9	3.3	62.9
1986	541	44	9.5	53.5	5.6	57.0
1987	579	38	10.9	48.9	4.5	53.1
1988	648	69	12.8	81.8	6.4	50.6
1989	686	38	15.9	53.9	3.4	43.1
1990	730	46	18.0	64.6	3.5	39.3
1991	736	6	18.7	24.7	1.3	39.4
1992/3	718	-18	18.1	-1.0	-	39.7
1993/4	707	-11	18.3	7.3	0.4	38.6
1994/5	660	-47	19.4	-27.6	-1.4	34.0
1995/6	640	-20	22.3	2.6	0.10	28.7
1996/7	692	52	22.7	1.1	0.10	30.5
1997/8	675	-17	26.4	3.1	0.10	25.6
1998/9	648	-27	27.4	1.0	0.04	23.6

* defined as ratio of gross addition of reserves to total production during year

Source: TERI Yearbook 2000/2001

Gas production

Gas producing regions in India

Natural gas production and development in India has undergone major growth in the last 30 years, growing from an annual production rate of 1.4 BCM in 1970/71 to 27.4 BCM in 1998/99.

There are three major areas of gas production in India today:

- The Western Offshore region which extends from offshore Mumbai to the Gujarat Coast
- Assam
- Gujarat onshore region

There are also gas fields in Rajasthan, Arunachal Pradesh, Tripura, the Cauvery basin and the Krishna-Godavari basin which is considered the most promising.

The current output is heavily concentrated in the western offshore fields accounting for 17.5 BCM of the total 27.4 BCM of gas produced in 1998/99. Onshore Gujarat fields produced 3.1 BCM gas.

Table 6.3 details natural gas production between 1975/76 to 1998/99. Substantial increase in exploratory and development drilling by ONGC during the 1980's led to a rapid rise in the indigenous crude and the accompanying associated gas production as well as natural gas production from the free gas fields. Some 60% of the natural gas in India is produced alongwith crude oil as associated gas and the rest as free gas.

Historically, production levels have fallen short of targets set in India's Five-Year Plans. Under the Eigth Five Year Plan, which ended in March 1997, gas production fell 19% short of the target. This was largely the result of lower than expected oil production rates due to a variety of technical reasons; deferment of projects, reservoir management rectifications, reduction in gas oil ratios, environmental problems, etc.

Western offshore

The Western Offshore region comprises the large Bombay High field and other associated gas fields. This region also has a number of free gas fields the largest of which is South Bassein. These offshore fields shown in Figure 6.2 are operated by ONGC.

The gas produced in the western offshore fields is brought on shore at Uran near Mumbai in Maharashtra and at Hazira near Surat in Gujarat. After fractionation to extract NGL and LPG, the gas at Uran is consumed in and around Mumbai. Gas at Hazira is sour gas which, after sweetening and NGL/LPG extraction, is used in and around Hazira and fed into the HBJ pipeline which passes through the states of Gujarat, Madhya Pradesh, Rajasthan, Uttar Pradesh, Delhi and Haryana.

Figure 6.2 Western offshore fields and gas pipelines

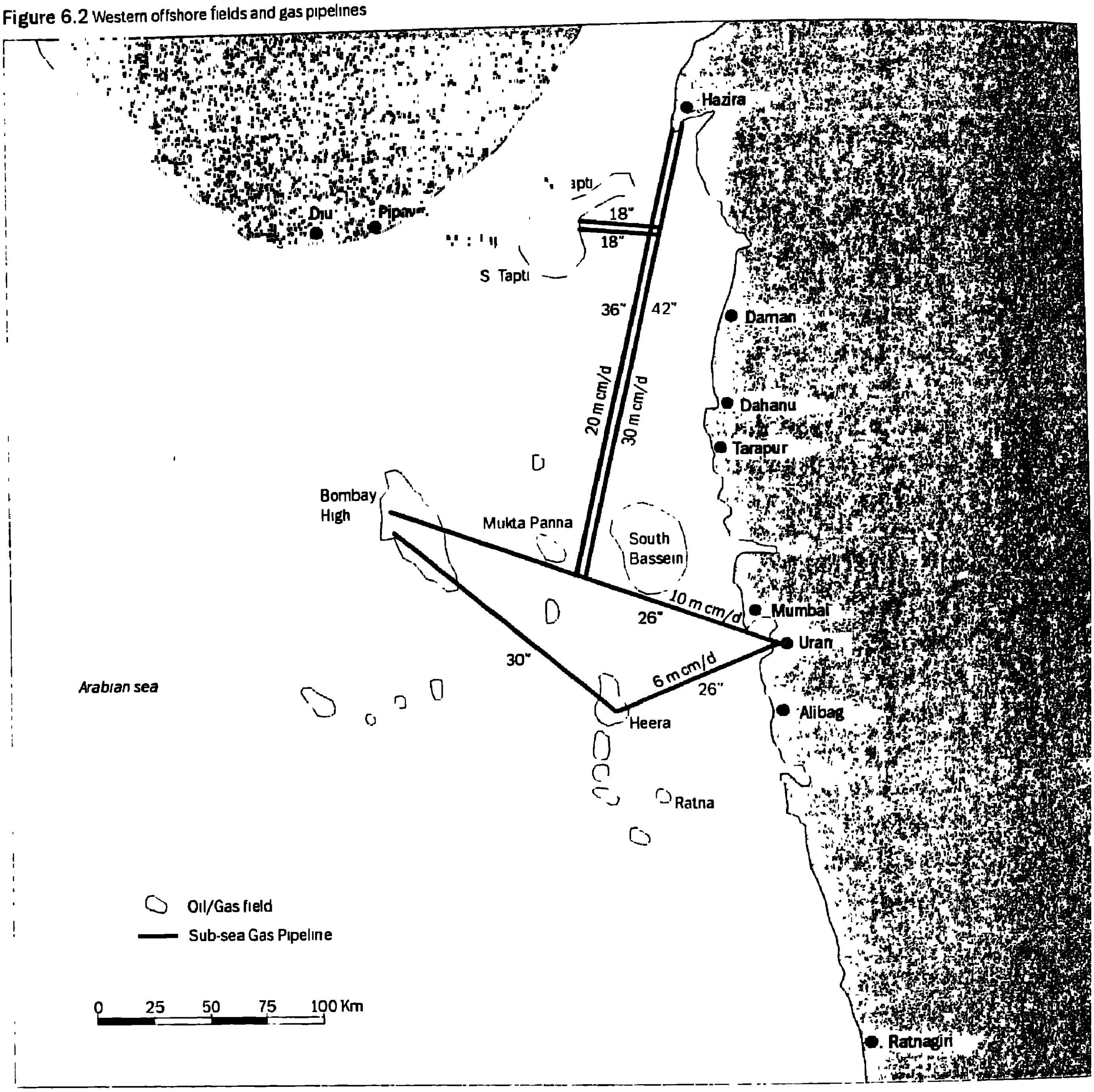


Table 6.3 Production of natural gas: 1975/76 to 1998/99 (million cubic meters)

State	1975/76	1980/81	1985/86	1990/91	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	1998/99
Natural gas production												
Onshore												
Gujarat	773	842	919	1696	1698	1946	2166	2462	2878	2932	3115	3166
Assam/Nagaland	1595*	843*	2035*	2011	31	52	47	1909	1880	1941	2018	2055
Arunachal Pradesh	-			29	271*	676*	788*	37	32	23	24	24
Tripura	-	-	-	70				97	131	154	196	307
Tamil Nadu	-	-	-	64				98	117	92	95	107
Andhra Pradesh.	-	-	-	46				640	679	799	1022	1218
Rajasthan	-	-	-	-	-	-	-	-	12	10	148	163
Total of which	2368	1685	2954	3916	4251	4708	4979	5243	5729	5951	6618	7040
Oil India Ltd	-	-	-	1518				1435	1433	1467	1670	1713
ONGC (Oil and Natural Gas Corporation Ltd)	-	-	-	2398				3808	4296	4484	4948	5237
Offshore												
ONGC	-	673	5180	14082	14394	13352	13356	14138	16579	16794	18102	17514
Private/Joint venture company	-	-	-	-	-	-	-	-	331	510	1681	2874
Grand total	2368	2358	8134	17998	18645	18060	18335	19381	22639	23255	26401	27428

*Includes Tripura, Tamil Nadu, and Andhra Pradesh

Source. TERI Yearbook 2000/2001

Bombay High

Discovered in 1974, with initial total gas reserves of some 400 BCM, Bombay High field is by far the largest associated gas field in India. Production from the field is expected to gradually decline. In recent years, a significant amount of work has gone into investigating the field production, some funded by the World Bank. At times, there has been speculation that an outside operator may be brought in to assist on the field development/ rehabilitation, but so far the field remains under the stewardship of ONGC. Remedial schemes to boost oil production will not necessarily increase the net gas production, as additional gas may be used in an injection programme.

There will be an opportunity to utilise the gas cap, estimated at 70-80 BCM, after the recoverable oil reserves are exhausted.

Neelam

Discovered in 1987 , the Neelam associated gas field started producing in 1990 with ONGC as the operator. Production levels are relatively low at around with 2 MMcm/day.

Performance during the Eighth Five Year plan period (1992-97) was lower than expected due to delays in project implementation and reservoir problems.

South Bassein

The Bassein field is India's largest free gas field and was discovered in 1976. Development of the field was delayed by slow progress in planned industrial development in western India, forcing ONGC, the operator, to shut in large gas volumes. The Hazira-Bassein link extension to the Bombay High field allowed the latter's increasing associated gas production to be supplied to Hazira, thus further delaying its development. Production from Bassein started in 1986 and reached a level of 30 MMcm/day by 1998.

Recent production from the field has been better than anticipated, indicating the possibility of more in place reserves. 3D seismic work has already been undertaken and the assessment of this data in conjunction with more development drilling may result in potential upward revision of reserves.

Panna - Mukta - Tapti

These fields were discovered by ONGC during 1976/77 but were not developed. Panna is a small highly paraffinic oil field producing sour gas, Mukta is also a small oil producing field, while Tapti is a free gas field.

As part of the government initiative to step up activities for the development of the Natural Gas sector, these fields were offered for joint venture operation in 1994. The management of the fields was taken over by a consortium headed by Enron. Production in 1997/8 amounted to 2.9 MMcm/day of free gas from Tapti and 1.4 MMcm/day of associated gas from Panna Mukta fields.

Development work has since accelerated with a significant level of increase in both seismic and drilling operations giving rise to reports of bigger reserves. Enron has indicated that the Tapti field may produce gas upto 17 MMcm/day. This is considered optimistic and a figure of 8/9 MMcm/day appears to be achievable. The Tapti field development will require further infrastructure once gas production exceeds 6 MMcm/day.

North and South Gujarat

The Gujarat region is the second most important gas producing region in India. There are two main areas of gas supply, North Gujarat and South Gujarat fields, both of which are onshore and operated by ONGC.

Production from the Gujarat fields has increased steadily from less than 1 MMcm/day in 1970/71 to 9 MMcm/day in 1998/99. The fields supply gas through a pipeline network within the state of Gujarat to fertiliser and power plants and other industries to meet gas requirements of these consumers to the extent the gas production permits.

Krishna - Godavari

Discovered in the mid 1970's by ONGC, there are number of small onshore oil/ associated gas producing fields in Krishna - Godavari region and three offshore fields. In the early part of the Eighth Five Year Plan (1992 to 1997), gas from the Krishna Godavari onshore fields was either regulated or shut in due to a lack of off-takers, reducing the planned production. Local infrastructure problems have since been largely resolved and gas production now exceeds 4 MMcm/day. This rate of production is likely to increase substantially.

The ongoing offshore development was entrusted to the private sector. Operation of the Ravva field, originally part of the ONGC development, was handed over to a JV company in 1994 and the field is now being operated by Cairn Energy. Gas production from this field was 0.7 MMcm/day in 1998 and is projected to increase. In June 2001 Cairn Energy announced that one of their exploratory wells was yielding more than 2 MMSCMD of gas and could point to a major gas discovery with reserves in the range of 21 to 28 BCM.

Cauvery basin

With the first oil discovery by ONGC in this region, development of the Cauvery Basin in Tamil Nadu began in the mid 1970's holding promise for production of some associated gas. Gas production has been lower than expected due to problems associated with an increasing water cut. Production level at 0.25 MMcm/day of gas was expected to rise but the results have not been encouraging.

Two offshore oil fields PY-1 and PY-3 are operated by a joint venture led by Hardy Oil. Due to only small associated gas quantities being available from these two fields, gas pipeline infrastructure has been uneconomic to develop and the associated gas is flared.

Assam - Tripura - Arunachal Pradesh

Assam is the oldest oil and gas producing region in north-eastern India, but has been one of the most difficult to develop due to its remote location and political difficulties. Gas is mainly associated with the oil production in Assam, while in Tripura wedged between gas-rich Bangladesh to the west and Myanamar to the east, there are free gas fields.

Gas production from Assam stands at 5.6 MMcm/day at present. There is only a small level of production from Arunachal Pradesh, of the order of 0.05 MMcm/day. Production in Tripura is presently below 1 MMcm/day but ONGC's gas bearing wells can yield gas production of around 3 MMcm/day, subject to sufficient demand getting generated. The Ninth Five Year Plan production estimates forecast gas production rising to 7 MMcm/day from the North East. There has been large amount of flaring of gas in this region, due to a lack of off-takers. It is estimated that 10-15% of the associated gas is currently flared.

The Assam area has the potential but will take political effort to initiate development. OIL has indicated that there are around 30 BCM of non-associated gas reserves so far discovered in Assam during the course of exploration for hydrocarbons.

Rajasthan

A few small gasfields have been discovered in Rajasthan and two have been developed. OIL and ONGC are producing 0.4 and 0.03 MMcm/day respectively to feed the RSEB power plant at Ramgarh. The fields have the potential to produce 0.55 MMcm/day for 15 years. The gas in this region is high in nitrogen and CO_2. Nevertheless interest has been shown in the area, with Shell having successfully drilling a well in early 1998. The operation of this well has now been taken over by Cairn Energy.

Current production output

Tables 6.4 and 6.5 provide the state-wise gross and net production of natural gas in India and Industry-wise offtakes of natural gas in India during the last decade.

Table 6.4 State-wise gross & net production of natural gas in India (million cubic meters)

State/utilisation	1980-81	1990-91	1995-96	1996-97	1997-98	1998-99	1999-00*
Assam[@]							
Gross production	843	2040	1924	1974	2190	2243	2257
Re-injected	67	102	-	-	-	-	-
Flared	257	621	131	97	292	313	221
Net production	519	1217	1793	1877	1898	1930	2036
Gujarat							
Gross production	842	1696	2878	2932	3115	3166	3096
Re-injected	-	-	-	-	-	-	-
Flared	146	402	279	347	358	397	412
Net production	696	1294	2599	2585	2757	2769	2684
Tamilnadu							
Gross production	-	64	117	92	95	107	138
Re-injected	-	-	-	-	-	-	-
Flared	-	55	96	49	48	67	51
Net production	-	9	21	43	47	40	87
Andhra Pradesh							
Gross production	-	46	679	799	1022	1218	1363
Re-injected	-	-	-	-	-	-	-
Flared	-	5	-	-	-	-	16
Net production	-	41	679	799	1022	1218	1347
Tripura							
Gross production	-	70	131	154	196	306	353

State/utilisation	1980-81	1990-91	1995-96	1996-97	1997-98	1998-99	1999-00*
Re-injected	-	-	-	-	-	-	-
Flared	-	-	-	-	-	-	-
Net production	-	70	131	154	196	306	353
Bombay High							
Gross production	673	14082	16579	16794	18102	17514	17774
Re-injected	-	-	-	-	-	-	-
Flared	366	4047	613	819	876	745	716
Net production	307	10035	15966	15975	17226	16769	17058
Private/JVCs							
Gross production	-	-	331	510	1681	2874	3465
Re-injected	-	-	-	-	-	-	-
Flared	-	-	318	448	305	190	144
Net production	-	-	13	62	1376	2684	3321
Total							
Gross production	2358	17998	22639	23255	26401	27428	28446
Re-injected	67	102	-	-	-	-	-
Flared	769	5130	1437	1760	1879	1712	1560
Net production	1522	12766	21202	21495	24522	25716	26886

@: including Arunachal Pradesh and Rajasthan

Source: Ministry of Petroleum & Natural Gas statistics 199-2000

Table 6.5 Industry-wise offtake of natural gas (million cubic meters)

Industry	1980-81	1990-91	1995-96@	1996-97@	1997-98@	1998-99@	1999-00@
Energy purposes							
Power generation	492	3634	6836	6935	8114	8714	9143
Industrial fuel	163	827	2301	2631	3106	3005	2502
Tea plantation	45	89	111	130	117	147	147
Domestic fuel	14	50	178	184	206	193	257
Captive use/LPG shrinkage	176	1775	589	618	569	911	900
Total A	**890**	**6375**	**10015**	**10498**	**12112**	**12970**	**12949**
Non-energy purposes:							
Fertilizer industry	611	5612	7602	7625	8752	8869	8917
Petro-chemicals	5	409	474	509	649	650	686
Others	16	370	-	-	-	-	1254
Total B	**632**	**6391**	**8076**	**8134**	**9401**	**9519**	**1085[illegible]**
Grand total (A+B)	**1522**	**12766**	**18091**	**18632**	**21513**	**22489**	**2380[illegible]**
%age to grand total							
Energy purposes	58.5	49.9	55.4	56.3	56.3	57.7	
Non-energy purposes	41.5	50.1	44.6	43.7	43.7	42.3	

*Provision @ Excludes offtakes of Natural Gas by ONGC

Source: Ministry of Petroleum & Natural Gas statistics 1999-2000

Gas flaring

Large quantities of natural gas were flared in the past, primarily due to lack of downstream offtake. In the 1980's, the flaring of gas was at levels of 35-40% of gross production. A significant effort has been made over the years to utilise the available gas and by 1996/97 the quantity of gas flared was reduced to 5.5% of gross production. Gas flaring is now mainly limited to Assam where there is insufficient infrastructure to utilise the associated gas.

Changing profile of oil/gas explorers and producers

The exploration and production of gas, as in the case of oil, has been dominated by public sector enterprises under the administrative control of the Ministry of Petroleum and Natural Gas.

Until recently, all the oil and gas in India was produced by two state owned companies, Oil and Natural Gas Corporation Limited (ONGC) and Oil India Limited (OIL). ONGC has been the dominant company accounting for over 90% of production.

Although the state owned companies increased hydrocarbon production and reserves significantly over the period 1975 to 1990, deficits are rising. Initiatives were therefore taken to encourage private sector investment in E&P sector, with exploration acreage offered to private companies under production sharing arrangements with the Indian government. Since 1994, the Government has awarded two medium sized discovered fields for development through joint ventures and 18 small discovered fields for operation by private companies.

The profile of exploration companies operating in India has undergone a further change with the recent launching of the more attractive NELP which has yielded a better response from the private sector companies. Of the of 22 blocks awarded under the first round of the NELP, the private sector Reliance Industries-Nikko Resources consortium was awarded nine shallow water and three deep water blocks and Cairn Energy has been awarded one block. In both cases, the private sector companies made bids on their own without having to form joint ventures with public sector companies. Bids have since been invited for 25 more blocks under NELP. A couple of Indian public sector companies earlier confined to downstream activities are now joining hands with ONGC to bid for blocks under the NELP. Exploration and production of natural gas will thus no longer remain the preserve of the two public sector companies, ONGC and OIL and addition of new players particularly from the private sector has made a useful beginning.

Gas supply infrastructure

Offshore

Infrastructure for gas supply to processing terminals is located mainly in the western offshore region, which accounts for over 60% of the proven gas reserves in the country and is by far its largest gas producing region. Figure 6.2 depicts this infrastructure.

A 26" dia pipeline was first laid by ONGC to transport associated gas from Bombay High oilfield to the shore terminal at Uran near Mumbai. Later on, an additional 30" dia pipeline was laid to connect Bombay High to Heera and Neelam oil fields along with a 26" dia pipeline to carry associated gas to the Uran terminal.

On subsequent development of the large free gas South Bassein field, a 36" dia pipeline was laid by ONGC to carry gas from this field to another large shore terminal set up at Hazira near Surat. The small oil fields at Mukta and Panna were connected to this pipeline for transportation of associated gas from there to Hazira. The free gas Tapti field is also connected through two 18" dia pipelines to South Bassein-Hazira pipeline. Since the capacity of this pipeline fell short of requirements, ONGC have recently commissioned a second 42" dia pipeline from South Bassein to Hazira terminal.

Onshore

The terminal at Uran near Mumbai can handle 16 MMcm/day of sweet gas, with limited facilities to treat sour gas. NGL and LPG separation facilities exist at Uran and after their separation, the residual gas is delivered to consumers through a pipeline network. A new terminal has been recently put up at Usar, south of Uran on the west coast to handle 41 MMcm/day of gas. A gas supply pipeline feeds Usar with the surplus gas which cannot be handled at the Uran terminal.

The Hazira terminal in South Gujarat is equipped with gas sweetening facilities for treatment of sour gas from South Bassein and other offshore fields. Apart from NGL and LPG separation facilities, fractionation facilities have been recently put up at Hazira terminal to produce naphtha and kerosene from NGL. The residual gas is distributed ex Hazira terminal through the HBJ pipeline and a local area network.

Coal bed methane

One of the promising new alternative energy sources is Coal Bed Methane (CBM). CBM is methane permeated in the coal seam matrix. Because of its explosive nature, it has been long considered as a potential menace to mining operations. Of late CBM is being viewed as an energy source rather than a hazard. With expectations of declining gas production, the Government is keen on exploiting the CBM potential. Accordingly, in April 2001, seven CBM blocks were put on offer from competitive bidding for exploration.

While a number of estimates for CBM resources in the country have been presented, a conservative estimate pegs the same at 850 BCM with the Gondwana basin accounting for 837 BCM and 13 BCM in tertiary basins. The work programme for exploiting CBM, as presented by the Directorate General of Hydrocarbons, indicates a lead time of 13 years to commercial production. It is expected that the CBM production could be initiated only by 2014. The National Energy Board in

Canada has used a recovery factor of 44% to assess marketable CBM reserves. Extending the same to the Indian case, annual stabilised gas production is estimated at 46 MMSCMD. However, gas production in the initial years (2015) is expected to be only a fourth of this level, i.e., 12 MMSCMD.

Gas hydrates

Another resource with a long-term potential is gas hydrates. A gas hydrate is a crystalline solid consisting of gas molecules, usually methane, each surrounded by a cage of water molecules. Methane hydrate is stable in ocean floor sediments at water depths of greater than 300 meters and is known to cement loose sediments in a surface layer several hundred meters thick.

Because the gas is held in a crystal structure, gas molecules are more densely packed than in conventional gas traps. Gas-hydrate-cemented strata also act as seals for trapped free gas. These traps provide potential resources, but they can also represent hazards to drilling. In addition, production of gas from hydrate-sealed traps is somewhat sustainable in nature as the reduction of pressure caused by production can initiate a breakdown of hydrates and a recharging of the trap with gas.

The National Institute of Oceanography has mapped out 6150 trillion cubic metres of gas hydrates along the southern coastline of the Indian peninsula. It is noteworthy that projected hydrate resources are about 9000 times the current gas reserves in India. The National Gas Hydrates Programme launched under the 9th Five-Year Plan involves an outlay of Rs 2130 million. However, unlike CBM, gas production from hydrates is not a commercially proven technology as yet and given the very preliminary stage of efforts, gas production from hydrates has been excluded from possible supply sources in this study.

Gas supply-demand projections

Officials estimates on domestic gas production indicate a declining trend. Gas in the Western Offshore region, which accounts for about 60% of the current gas production, comes from basins that are already in the mature stage of exploration and hence, little incremental output is expected from them. On the other hand, the prospects of additional gas from the Krishna-Godavari basin look promising. Aggregate gross production, however, is expected to decline from 78 MMSCMD in 1999 to 37 MMSCMD by 2015.

Based on the most "likely' estimates of gas demand presented in Chapter 6, the gas supply-demand balance for the country is summarised in Table 6.6

Table 6.6 Projected gas supply-demand balance (MMSCMD)

Year	Gas demand (MMSCMD)	Domestic gas availability (MMSCMD)			Gas imports	
		Natural gas	CBM	Total	(MMSCMD)	(MMT)
1999	59.4*	65.2#	-	65.2#	-	-
2005	102.7	64.8	-	64.8	37.9	10.0
2010	127.6	64.4	-	64.4	63.2	16.8
2015	150.8	36.7	11.6	48.3	102.5	27.3

*Sales which exclude gas for captive use, LPG shrinkage and other non-energy uses

#Net gas production less offtakes by ONGC

These projections indicate an import dependence of the order of 37% by 2005 50% by 2010 and 68% by 2015.

7

Gas imports

Source of piped gas imports

A number of countries, in the Gulf, South East Asia and Australasia have sizeable natural gas reserves under exploitation or development.

Table 7.1 Proven gas reserves of countries in the Gulf, Central and SE Asia

Country	Proven gas reserves 2000 (BCM)	Production 2000 (BCM)	R/P ratio (years)
Gulf			
Iran	23,000	60.2	>100
Qatar	11,150	28.5	>100
UAE	6,100	39.8	>100
Central Asia			
Turkmenistan	2,860	43.8	65
SE Asia/Australasia			
Indonesia	2,050	63.9	32
Australia	1,260	31.1	40
Malaysia	2,310	44.2	52
Bangladesh	300	10.3	29

Source: BP statistical review of world energy, June 2001

Gas production has been taking place since the 1970's in UAE, Malaysia and Indonesia for domestic use and exports as LNG. Other sources like Qatar have opened up to international markets for LNG exports recently. Gas reserves in Iran and Turkmenistan are under-exploited due to lack of access to export markets arising from political difficulties.

Imports of gas through transnational pipelines to meet the existing and projected shortfall in gas availability in India has been under investigation from Oman, Iran, Turkmenistan, Bangladesh and Myanamar which are located in the vicinity of India.

Prospects of import through pipelines

Technological considerations

Laying sub-sea pipelines via a deep sea route (e.g. proposed Oman - India gas pipeline at a water depth of 3500 metres) poses a major technical challenge as no pipeline has yet been laid at these depths. According to the industry assessment, much work remains to be done to establish the technical viability of pipeline laying and of the intervention systems needed for repair and maintenance of pipelines. Even after attaining this capability, the unduly high cost of laying a deep water pipeline may render the project economically unacceptable.

Problem of political relationships

Unlike the deep water pipelines, the laying of long distance gas pipelines on land is a well proven and mature technology reflected by successful laying and operation of these pipelines in Europe, U.S.A and India itself. However, the problems of such pipelines traversing national boundaries emanate from the type of political relationships existing between the concerned countries and can multiply with the number of international borders to be crossed. The key issues relate to reliable assurance on security of gas supply to the recipient country at an acceptable transport cost in the face of the potential ability of the transit countries to demand unreasonably high tariff charges or turn hostile, threatening security of the pipeline. The long term supply arrangements associated with such projects thus warrant mutual appreciation of economic interests and political understanding amongst the supply, transit and receiving countries.

Proposals for gas pipelines to India

The status of each pipeline proposal mooted for gas imports into India is as follows:

Oman-India pipeline

Conceived as an ambitious project by the Oman Oil Company (OOC) at a cost of $ 5 billion, it envisaged laying two sub-sea gas pipelines at 3500 metres water depth to carry 20 BCM per annum from the Sayh Rawl gasfield in Oman to Bachau in Gujarat state. The pipelines were to follow a deep sea route to India outside the Pakistan extended economic zone (EEZ). A study was commissioned by OOC to establish the technical feasibility of this project which could not be proved.

Availability of adequate proven reserves of gas in Oman to support this project, particularly after commissioning of their LNG terminal, also came under questioning. Consequently, OOC announced their decision to give up the proposal.

Iran-India pipeline

The plan to export Iranian gas to India has the full support of the governments of both the countries who enjoy cordial relations. With its vast gas reserves and proximity to India, Iran offers a reliable gas supply source to India and considers India as one of its biggest and nearest potential markets.

Iran-Pakistan-India onshore pipeline

An obvious route would be to cross Pakistan and enter India in the western Rajasthan region. Initially, Pakistan was averse to the proposal despite the fact that it could earn around $ 600 million by way of transit fees. Of late, Iran has been able to persuade Pakistan to resile from their stand. India too was opposed to the onshore route due to security considerations, but in June 2001 agreed to a detailed feasibility study being carried out on the premise that Iran would provide all necessary safeguards with respect to delivery of gas to India. NIOC has awarded the feasibility study to BHP, Australia.

Iran-India offshore pipeline

An MoU was signed between the governments of Iran and India in 1993 to examine the feasibility of laying an offshore gas pipeline, outside the territorial waters of Pakistan, leading into Kutch in India. A feasibility study in early 1995 got stalled due to Pakistan government's refusal to give permission for carrying out an offshore survey within the EEZ of Pakistan.

An Indo-Iranian joint working group constituted by the two governments with respect to in the year 2000 decided to commission a study to explore the possibility of laying a deep-sea pipeline from Iran that skirts Pakistan's EEZ. NIOC has recently awarded the feasibility study to Snam Progetti of Italy. The deep sea route from Iran to India, traversing rock outcrops, steep slopes and canyons, calls for a critical investigation whether an acceptable pipeline route can be identified. Moreover, the relatively high cost of this pipeline may reflect on the feasibility of this project. India will expect the same guarantees from Iran as in the case of the onland route.

Turkmenistan-Afghanistan-Pakistan-India pipeline

A consortium led by Unocal viz. Central Asia Gas Pipeline Limited, examined the proposal to develop a 1250 km long gas pipeline from Turkmenistan's Daulatabad field to Multan in northern Pakistan. The pipeline was to be designed with the aim of extending it to north India over a distance of 600 to 700 km. Studies undertaken envisaged no unusual engineering challenge to constructing the pipeline system over a period of two years at an estimated cost of $ 2.0 to 2.5 billion. No further progress could be made because of political unrest and totally unsettled conditions in Afghanistan.

A joint working group was subsequently set up in May 1999 by the governments of India and Turkmenistan to study the possibility of gas transportation from Turkmenistan to India without passing through Afghanistan. One option was to lay a gas pipeline from Turkmenistan to Iran from where supplies could reach India.

However, the same problem would be faced as in the case of the Iran - India pipeline.

Bangladesh-India pipeline

Multinational oil companies engaged in oil/gas exploration and production activities in Bangladesh have been pressing for natural gas exports to India on the strength of some recent discoveries. They have prepared plans for laying gas pipelines from Bangladesh to India after getting gas demand studies undertaken in India to determine potential routes for these pipelines. The enthusiasm of these companies is, however, not shared by the Bangladesh government and the state oil company, Petrobangla, who feel that the gas reserves discovered so far are insufficient to support significant export projects.

There is strong political opposition in Bangladesh to gas exports to India. There is talk of value added export like setting up gas based power plants in Bangladesh for exporting power to India instead of gas. National Thermal Power Corporation, the state owned power generation company in India, had submitted a proposal to Bangladesh Power Development Board for setting up a gas based power plant in that country of a capacity to be chosen by Bangladesh but its outcome is not known.

Nonetheless, two recent gas export proposals were submitted by the multinational companies, Unocal and Shell for consideration of the Bangladesh Government.

Unocal's proposal

It envisages a 1350 km long pipeline of 5 BCM per annum capacity to transport and sell the excess gas produced from Unocal's gas field at Bibiyana in Bangladesh to Indian power and fertiliser companies and other industries. Starting from Rashidpur in Bangladesh the pipeline will pass through the eastern Indian states of West Bengal, Bihar and Uttar Pradesh and ultimately connect with the HBJ gas pipeline at an estimated cost of US $ 910 million. It will provide a much needed gas link between the eastern and western regions of India. Unocal has entered into an MoU with the Uttar Pradesh state government in March 2001 offering gas supplies to interested industries in the state on the route of the pipeline.

Shell proposal

Shell is equally keen to lay a gas pipeline to India. It took over the operations of the producting Sangu gas field in Bangladesh from Cairn Energy on 1st July, 1999. Shell's proposal consists of laying a gas pipeline from the Sangu gasfield following the same alignment proposed by Unocal, marketing gas to industries enroute and ultimately connecting to the HBJ gas pipeline. Like Unocal, Shell entered into an MoU on similar lines with the Uttar Pradesh state government in March, 2001. An additional offer made by Shell was to bring gas from the LNG terminal to be set up at Hazira for meeting the requirements of consumers in parts of Uttar Pradesh which are away from the route of the proposed pipeline from Bangladesh.

General Elections are due to he held in Bangladesh in the near future. The new government is to decide whether a change in thinking on gas exports to India is called for. Unocal and Shell could then consider jointly developing a common pipeline from Bangladesh to India or deliver gas at the border from where GAIL could build a pipeline linking at Auraiya to the HBJ pipeline.

Myanmar-India pipeline via Bangladesh

Bulk of the discovered gas off the Myanmar coast has been committed for supply to Thailand. Further exploration continues and if more gas becomes available, it may be feasible to transport it to India through an offshore pipeline in combination with gas from Bangladesh. The offshore pipeline route in the Bay of Bengal would pass through areas of extremely high currents and areas prone to seabed movement requiring investigation of pipeline stability apart from other technical issues. This proposal is dependent on Bangladesh's cooperation.

Outlook-Gas pipeline projects

It is evident that none of the pipeline projects for gas imports into India will materialise in the near future. However, taking a long term view upto the year 2015, gas imports by pipeline may fructify from two sources;

- Unocal and Shell may jointly develop a 5 BCM per annum project to supply gas from Bangladesh, to India.
- An Iran-India pipeline via Pakistan may succeed if there is satisfactory resolution of the security issues. Given the large gas reserves in Iran, the initial capacity of this pipeline may well be at a level of 20 BCM per annum.

LNG imports

In view of the problems faced by the gas pipeline projects, LNG import options have been pursued to meet immediate needs for imported gas. Proposals for constructing LNG terminals have been made by various consortia of Indian and multinational oil and gas companies and promoters of power plants. The LNG trade is undergoing a transformation as new suppliers emerge in West Asia. The downturn of LNG demand in South Korea and Japan has made India a key market for LNG.

LNG sources for India

A tender inviting offers for LNG supplies to the proposed LNG terminals at Dahej and Kochi received bids from Qatar, Oman and Yemen in the Gulf and Australia, Indonesia and Malaysia in the east.

The supply sources identified by promoters of LNG import terminal proposals in India are listed in Table 7.2.

Table 7.2 Identified sources of supply to proposed LNG terminals in India

LNG terminal	Capacity (MMTPA)	Supply source	Remarks
Jamnagar	5.0	Iran	
Pipavav	3.0	Under identification	MoU signed earlier with Yemen voided
Dahej	5.0	Qatar	
Hazira	5.0	Shell group's sources	
Trombay	3.0	Total Elf Fina sources	
Dabhol	5.0	Oman (1.7 MMTPA) Abu Dhabi (0.54 MMTPA)	Balance quantity yet to be sourced
Kochi	2.5	Qatar	
Ennore	2.5	Qatar	
Kakinada	2.5	To be decided	Malaysia, a contender
Gopalpur	5.0	Australia	
Total	38.5		

Proposed LNG terminals in India

Some of LNG import terminal proposals approved in principle by the Government of India have since been given up by the promoters. The ten proposals listed in Table 7.2 are shown in Figure 7.1. The shipping arrangements for LNG supply to these terminals are collectively covered towards the end of the chapter.

Jamnagar LNG terminal

Proposed natural gas liquefaction facility in Iran

The Reliance group of India has entered into a MoU with the National Iranian Oil Company (NIOC) and British Petroleum (BP) to set up a 8 MMTPA liquefaction facility for natural gas in Iran. Gas from Iran's offshore South Pars Field-Phase II is to be transported through a pipeline to Assaluyeh on the Persian Gulf where the liquefaction plant is to be put up along with LNG export facilities. This is the first MoU signed by NIOC for development of a LNG export terminal in Iran.

A joint venture company is under formation to take in hand work on the above liquefaction and export facility. While its name is still to be decided, the equity shareholding is likely to be NIOC-40%, Reliance-25% and BP-25%, with the remaining 10% to be allotted to a fourth partner yet to be selected. Terms of the JV agreement and size of the equity base of the new company are being discussed between the partners. Meanwhile, GAIL is staking its claim for equity participation in the JV to be formed.

Reliance is expected to get marketings rights for 5 to 6 MMTPA of LNG. BP will, in that case, draw the remaining 2 to 3 MMTPA of LNG for marketing themselves.

Detailed feasibility study of the liquefaction facility

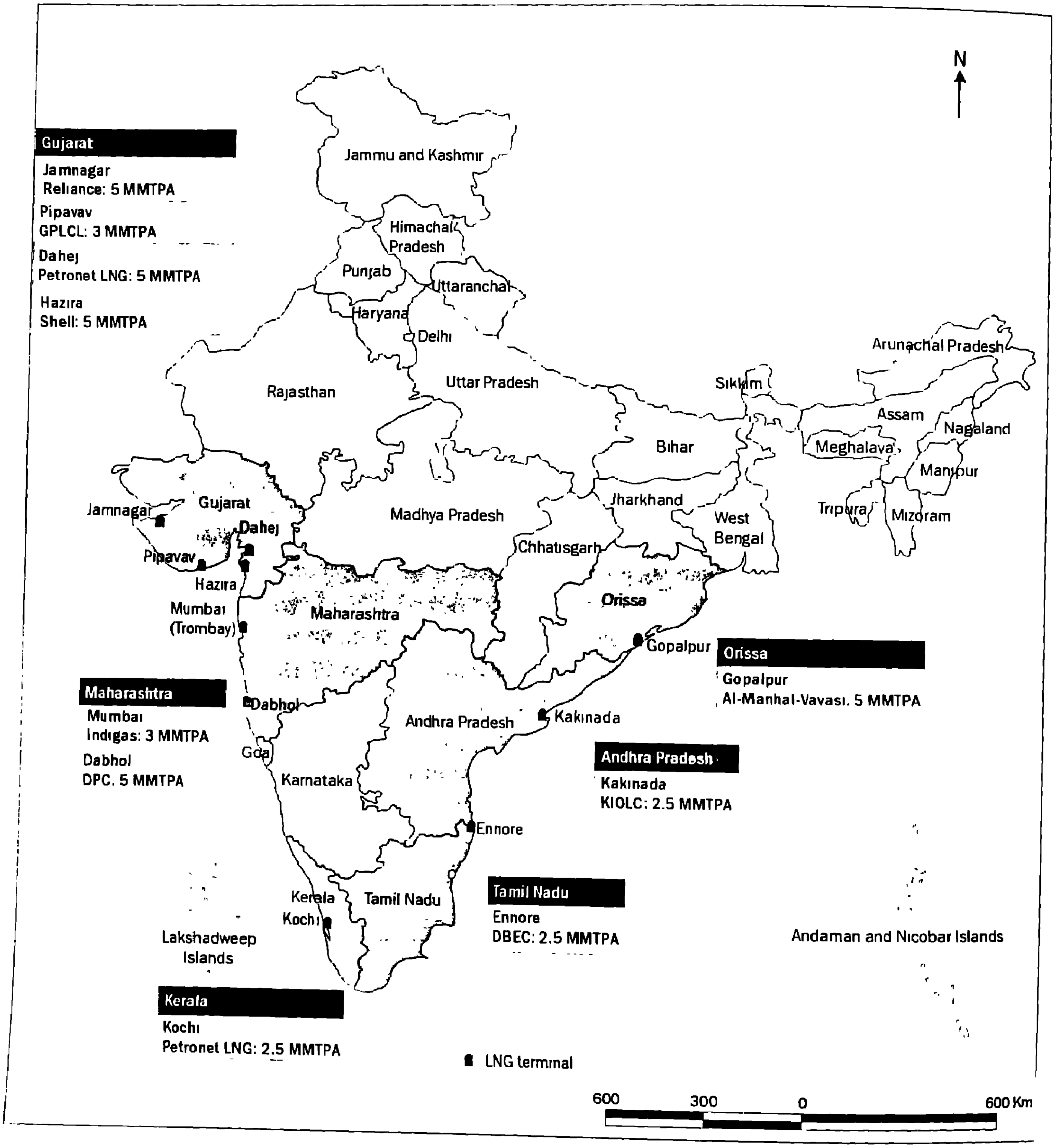
The NIOC-Reliance-BP consortium is to immediately undertake a detailed feasibility study of the proposed project. The possibility of LNG exports to India will be closely examined by the consortium, amongst other available options for LNG exports. Reliance will take the lead in conducting the LNG market study, BP will examine the technical aspects of the project and NIOC will be involved in all facets of the study.

It is envisaged that the study will be completed by end 2001. With construction of the gas liquefaction and LNG export facilities yet to start the earliest this project may become operational is by end 2007.

The LNG terminal

For despatch of petroleum products by ocean going tankers, the 27 MMTPA Reliance refinery at Jamnagar has a jetty extending nearly 7 km into the sea with 4 berths (A to D) located at the farthest 3 km section of the jetty. The draught available progessively increases from the first jetty `A' to 14 to 15 metres at the farthest jetty `D' which is suitable to receive LNG tankers of 135,000 cu metres capacity. The tidal waves at Jamnagar do not pose any severe problem to warrant construction of a breakwater. Reliance also has spare land available on shore and is thus in a position to use its existing infrastructure to construct the LNG import terminal relatively quickly.

Figure 7.1. Proposed LNG terminals



Gujarat

Jamnagar
Reliance: 5 MMTPA

Pipavav
GPLCL: 3 MMTPA

Dahej
Petronet LNG: 5 MMTPA

Hazira
Shell: 5 MMTPA

Maharashtra

Mumbai
Indigas: 3 MMTPA

Dabhol
DPC. 5 MMTPA

Kerala

Kochi
Petronet LNG: 2.5 MMTPA

Tamil Nadu

Ennore
DBEC: 2.5 MMTPA

Andhra Pradesh

Kakinada
KIOLC: 2.5 MMTPA

Orissa

Gopalpur
Al-Manhal-Vavasi. 5 MMTPA

Pending outcome of the study, the capacity of the terminal is tentatively planned at 5 MMTPA, with provision to enlarge the capacity to 10 MMPTA in the second stage.

In due course the Reliance group may float a holding company in India, which will have:

(a) an interest in the JV company to be formed for the gas liquefaction and LNG export facility at Assaluyeh in Iran

(b) a separate gas transportation and infrastructure company as a 100% subsidiary for the Indian operations.

(c) a separate marketing company as a 100% subsidiary to market regasified LNG.

Pipavav LNG terminal

The port of Pipavav

Located on the west coast of India in the state of Gujarat, Pipavav is the country's first port developed, post liberalisation of the India economy, with private sector initiative, capital and management. The promoters, Seaking Infrastructure Limited (SIL) in equity partnership with Port of Singapore Authority, the U.K. based multilateral agency -The Commonwealth Development Corporation and the two Indian financial institutions - IDBI and UTI, formed the company "Gujarat Pipavav Port Limited (GPPL) which undertook the development work and is now administering and managing the port operations.

Three islands protect the port from the south-westerly waves and monsoon swells, permitting safe navigation of the ships throughout the year. The port has a natural draught of 9.5 to 11 metres, which is dredged to receive ships upto 45,000 DWT. The 300 metres wide approach channel in the port is dredged to a depth of 12.5 metres. The port handles general bulk dry cargo vessels, container ships as well as packed cement cargoes at the captive jetty of Larsen & Toubro's cement plant located adjacent to the port. There is also a jetty 300 metres long with a separate terminal to receive LPG and liquid chemical vessels. During the year 1999-2000, the total traffic handled at Pivavav port was 4.5 MMT, including nearly 2.0 MMT at the captive jetty. Projection of traffic for the year 2001-02 is 6.5 to 7.0 MMT.

The road-rail connectivity to the port, which has been a hurdle for its growth, is now taking shape. An 11.6 km eight lane road now connects Pipavav to the coastal highway. A joint venture company between GPPL and the Railways will by 2002, link Pipavav by a 14 km new rail line to Rajula, and convert the 250 km Rajula - Surendranagar section from metre to broad gauge at a cost of Rs 2.94 billion (US $63 million).

The terminal

While planning the port, the prime promoters, SIL, had made provision for a separate LNG jetty and terminal next to the LPG import facilities. SIL subsequently formed a joint venture, Gujarat Pipavav LNG Limited (GPLNG), with British Gas (BG) to set up an LNG import terminal of 2.5 MMTPA capacity at Pivavav with 49% and 51% equity respectively, with capacity increasing in stages from 2.5 to 10 MMTPA. Whereas SIL was to offer the use of Pipavav port infrastructure and land, BG was to provide the technical expertise, construct the LNG jetty after dredging the channel from a draught of 9.5 to 13.5 metres, build the tank farm regasification facilities and send out facilities. The investment by BG also included laying of a pipeline over 150 km in length, including a 60 km sub-sea stretch, from Pipavav to Hazira to gain access to important gas consumers in and around in Hazira, and the strategic HBJ pipeline. It was also to enable BG to avail of the recently commissioned Hazira - Ankleshwar pipeline of their affiliate Gujarat Gas Company Ltd (GGCL) to further develop and enlarge gas marketing through GGCL's old infrastructure in South Gujarat. In view of these plans, GPLNG enhanced the proposed initial capacity of the Pipavav terminal from 2.5 MMTPA to 5.3 MMTPA and entered into an MoU with Yemen LNG in May 1998 for the supply of 5.3 MMTPA of LNG to Pipavav.

The above equation changed on 7th July 1999 when GPLNG signed on MoU with the state owned National Thermal Power Corporation (NTPC) granting it a 26% stake in the company. The carrot offered by NTPC was to agree to source its entire gas demand of 1.6 MMTPA exclusively from GPLNG for the proposed 650 MW second stage expansion of its Kawas and Gandhar power plants. The MoU stipulates that 50% of GPLNG's equity must be held by government owned companies and only the balance can be shared between companies in the private sector. This implies that BG and SIL have to dilute their combined 100% equity ownership to 50%. Under the Indian laws, a shareholder with 26% or more equity is entitled to certain statutory protections and whether SIL or BG accept less than 26% equity remains to be decided. Discussions between these shareholders have reportedly concluded and the JV agreement is to be drafted to reflect each other's claims and draw up a balanced arrangement. Also, the equity shareout needs to be finalised and a decision taken as to who will constitute the balance 50% share holding of the state owned companies, if NTPC wish to confine their share to 26%. The name of the company is also likely to change. It is not known whether NTPC's reported decision to put on hold investment in LNG power plants and by implication in LNG terminals, will have an impact on the Pipavav project.

LNG supplier

NTPC has sought cancellation of the MoU signed by GPLNG with Yemen LNG on the grounds that this agreement, having been made on the basis of a single offer, is not acceptable under the procedures followed by the state corporations. Consequently, a fresh open enquiry was issued by GPLNG in February, 2000 inviting "Expression of Interest" for the supply of 5.3 MMTPA of LNG. Eight probable suppliers have been reportedly short listed, which includes Yemen LNG. Tenders can be invited only after the name of the new company has been decided upon and the JV agreement is signed and registered.

The Pipavav LNG proposal thus came in for a major recast. Meanwhile, the progress made by the neighbouring LNG terminal proposals at Dahej and Hazira, has relegated the Pipavav proposal to the background. Pipavav's distance from the main gas consuming centres of Gujarat, the HBJ pipeline and the Hazira-Ankleshwar pipeline, adds to its handicap. Further the terminal capacity is likely to be 3 MMTPA initially and 5 MMTPA in the second phase. Scaling down of the capacity from 5.3 to 3 MMTPA at the first stage presumably takes into account the imminent competition from Dahej and Hazira terminals.

Dahej LNG terminal

The promoters

The Ministry of Petroleum & Natural Gas, Government of India approved the formation of a joint venture company in May, 1997 between GAIL, ONGC, IOC and BPCL to develop facilities for the import and utilisation of LNG. The company was incorporated in April, 1998 under the name of Petronet LNG Ltd (PLL) with an authorised capital of Rs 12 billion ($ 258 million) and received its certificate of commencement of business on June 1, 1998.

All the four promoters of PLL are the premier public sector companies in the Indian oil and gas sector and hold large market production shares in their respective areas of business. According to the Government directive, the combined equity share of these four companies is not to exceed 50% so that PLL operates as a private sector company. The other half of the equity can be shared with strategic partners, LNG suppliers, financial institutions and the banks and the balance equity is to be offered to the public. The emerging equity structure of PLL is as follows:

▪ GAIL, ONGC, IOC AND BPCL (12.5% each)	50%
▪ Gas de France (strategic partner - shareholder agreement signed)	10%
▪ Rasgas (LNG supplier)	10%

Gujarat State Government (through a nominated company in private sector in which the State government holds equity share, so that PLL retains the status of a non-government organisation)	5%
Financial Institutions, Banks, etc.	25%

The Government directive envisages that the company would set up LNG import terminals at Mangalore, Cochin/Kayamkulam, Hazira/Dahej, Ennore or other suitable identified locations. It would also consider participation in projects upstream and downstream of LNG terminals and in setting up or participating in power projects. PLL accordingly plans to put up two LNG terminals initially–at Dahej (5 MMTPA) and Kochi, earlier known as Cochin (2.5 MMTPA).

Suitability of Dahej as a port for the terminal

Situated in the Gulf of Cambay on the west coast of Gujarat state, Dahej owes its selection to the substantial gas demand in its vicinity from existing and prospective consumers. The present gas transmission infrastructure, i.e. the regional pipeline network of south Gujarat and the HBJ pipeline, both of which are in proximity of Dahej, can be effectively utilised for distribution of LNG after regasification.

PLL is satisfied that the, severe maritime conditions at Dahej due to high tidal variation upto 10.5 metres and 6 knot currents during the three monsoon months, can be overcome by constructing a high breakwater.

Features of the port

PLL was awarded a Letter of Intent by the Gujarat Maritime Board (GMB) for the development of a LNG-cum-solid cargo port at Dahej for commercial use on a 30 year concession under the build-own-operate-transfer (BOOT) policy framework of the Gujarat Port Policy, 1995. While PLL is in the process of developing the LNG terminal, it has invited Expression of Interest from parties who are willing to develop the solid cargo port as sub-concessionaires by forming a project company with some equity participation by PLL or its nominee.

The berth for LNG ships is to be constructed about 2 km south of the existing GCPTL liquid chemicals jetty at Dahej. A 2.5 km dedicated jetty will lead to the LNG berth and the draught at the jetty head will be 14.5 metres. A breakwater 660 metres long will be constructed high enough to withstand the severe maritime conditions during the monsoon period.

Land measuring 50 hectares close to the jetty site has been taken on lease by PLL from GMB for a period of 30 years. A Government notification of August, 2000 permits construction of the LNG terminal within the Coastal Regulation Zone.

Terminal facilities

Initial terminal capacity is to be 5 MMTPA expandable to 10 MMTPA. LNG storage will consist of 2 × 160,000 cubic metre tanks, with provision to add a third tank.

Project approvals

Environmental and other clearances by the Gujarat state government is in hand. In principle clearance from the Chief Controller of Explosives has been obtained. The vital approval of the Ministry of Environment & Forests, Government of India has also been received. Other clearances will be obtained by the EPC contractor.

EPC contract

The EPC contract was awarded in December 2000 at a fixed price to a group led by Japan's Ishikawajima - Harima Heavy Industries (IHI). The consortium partners include Toyo Engineering Corporation of Japan, Toyo Engineering India Ltd., Ballast Nedam International of the Netherlands, Itochu Corporation and Mitsui Company. Completion of the project is to be achieved in three years from the date of award of EPC contract , i.e. by end 2003.

Project cost

Total project cost estimate is Rs 25 billion ($ 537 million).

Project management

Foster Wheeler Energy Ltd. of the U.K. have been appointed as consultants for project management

Financial closure

PLL initially tied up a short term bridge loan of Rs 14 billion (US $ 301 million) from seven Indian banks and financial institutions for starting construction. The bridge loan with a two year maturity period carries an interest rate of around 11%. The four promoters of PL i.e. GAIL, ONGC, IOC and BPCL, who share between them 50% of PLL's equity, have contributed Rs 1 billion (US $ 21 million) as their advance equity contribution. Steps are simultaneously being taken to achieve financial closure by the end of 2001.

LNG supply

A long term sales/purchase agreement was signed by PLL in July 1999 with Rasgas of Qatar for the supply of 5 MMTPA of LNG (which can increase to 7.5 MMTPA by giving necessary notice) on fob basis. The 25 years contract effective July 2003 envisages a requirement of 5 MMTPA at Dahej and 2.5 MMTPA at Kochi but gives PLL the option to take the entire quantity of 7.5 MMTPA at Dahej. The LNG price payable by PLL will be variable and linked to the average price of a basket of crude oils.

Rasgas is reported to have agreed to give PLL a 5% stake in the 5 MMPTA LNG liquefaction - phase II plant in Qatar.

Gas marketing

It has been decided that gas will be marketed by the following companies in the indicated proportions GAIL 60%, IOC 30%, and BPCL 10%.

The companies will use the existing pipeline transmission infrastructure of GAIL who will be exclusively responsible for gas transportation for all marketers against payment of a transportation charge. Any additional pipelines to be laid will be the responsibility of GAIL.

Hazira LNG terminal

Project background

In 1997, the Gujarat Maritime Board (GMB) on behalf of the state government of Gujarat invited applications for the development of an all weather multi-cargo port at Hazira. The initiative was to be "LNG driven", as the large requirement for natural gas in north-west India would make the Hazira port project an attractive and viable proposition. The project received an enthusiastic response, most notably from Mobil, Reliance in partnership with Elf Aquitaine & Tractebel, and Shell. On 12 November 1999 Shell and its Indian partner Essar were awarded the rights to develop the project.

Shell on their own had selected Hazira to be most suitable for a LNG terminal after a technical and commercial evaluation of five locations. The following factors weighed in favour of Hazira:

- Its proximity to existing and potential gas consumers
- Good access to the hinterland for transportation of gas, liquid and solid cargoes
- It is a nodal input point for the state owned company, Gujarat State Petronet Limited which is to construct a gas grid in the state. It is also the on shore entry

point to the existing HBJ pipeline and the Hazira-Ankleshwar gas pipeline in which British Gas has majority holding.

Project promoters

The project is a 100% development by the Royal Dutch/Shell group. It has received support from Essar Investments Limited under a joint development agreement. While Essar are not taking any share in the equity initially, it and other value adding partners may do so at a later stage. Shell will retain the position of lead developer. This project is being constructed on balance sheet financing and therefore no financial closure is required.

Shell have floated two fully owned companies for the development of Hazira port and the LNG terminal. The Hazira Port Private Ltd. (HPPL) will provide all the facilities for a multi-cargo port at Hazira including development of a suitable approach channel, and reclamation of land from the sea. The Hazira LNG Private Ltd (HLPL) will handle installation of LNG storage tanks, receipt, regasification, transfer pipelines and send out facilities. Shell have recently obtained government approval to increase their investment from $130 million to $200 million.

The port

Location of Hazira port and terminal facilities has been planned on the sea verge beyond the CRZ into the sea and outside the inter-tidal area.

The port will consist of a 1000 × 1200 metres basin, with a draught of 14 metres. Vessels will approach the basin through a channel dredged to a draught of 12.5 metres but capable of being eventually dredged to 17.5 metres. A breakwater 1.2 km to 1.4 km long is to be put up at a water depth of 10 to12 metres.

In its first phase, the port will accommodate LNG vessels upto 145,000 cubic metres, dry bulk vessels upto 150,000 dwt, and general dry cargo vessels upto 30,000 dwt.

The port has been designed keeping in mind future expansion at reasonable cost. It is planned to progressively introduce strategic port partners into the port company to manage throughput of cargoes other than LNG. However, the port company (HPPL) will at all times have a minimum 26% Shell participation. KPMG has been appointed as port and non-LNG cargo consultant.

The LNG terminal

The capacity of the terminal will be 5 MMTPA capable of being doubled. Two double walled cryogenic tanks of 180,000 cubic metres capacity each are to be installed initially.

Project status

FIPB and CCEA clearances have been received. The Environmental Impact Assessment has been completed. Approvals have been received from the Gujarat Pollution Control Board and the CRZ administering authorities. The Ministry of Environment & Forests has accorded environmental clearance. Award of work to the selected EPC contractor is being finalized. Allowing between 30 and 36 months for construction, the LNG terminal may be ready by the first quarter of the year 2004.

LNG supply

Shell is uniquely placed to source and ship LNG not only from geographically convenient locations in the Middle East, but also from south-east Asia and Australia. The precise sources of supply have not yet been disclosed.

Trombay LNG terminal

Project promoters

India Natural Gas Company Pvt. Ltd (Indigas), a company owned equally by Tata Power Company (TPC), Total Gas and Power India (TGPI) - a wholly owned subsidiary of Total Fina Elf - and Gas Authority of India Limited (GAIL), is building the terminal facility at Trombay, Mumbai in Maharashtra state.

The terminal will have a capacity of 3 MMTPA. About 1 MMTPA will be consumed by TPC and the balance 2 MMTPA will be procured by GAIL for meeting the supply shortfall of their existing customers. The large latent demand for gas in the Mumbai region provides a ready market for an additional 3 MMTPA capacity to be developed in the second phase.

Site location

Adequate land with waterfront, in the existing industrial zone belonging to TPC, has been found suitable for the Terminal. TPC will provide all necessary infrastructure facilities and interfaces. They will also make available an all weather jetty, which they are licensed to construct under a BOOT Agreement with the Mumbai Port Trust for a concessional period of 30 years.

Terminal facilities

The jetty will be 3.5 km into the sea, allowing LNG vessels of 100,000 cubic metres capacity with a draught of 9.5 metres to be berthed. A pit with a minimum of draught 10 metres will provide an adequate turning circle for the ships. Cost of the jetty is estimated at $80 million. One 140,000 cubic metres capacity double walled

LNG storage tank with full containment and concrete roof is to be installed in the first phase.

Detailed feasibility study has been completed. Basic engineering has also been completed by Fluor Daniel. The financial advisor, viz. Societe Generale has been appointed and the financial model is in place. Short listing of EPC bidders is at a final stage of approval and the EPC documents are ready to be issued.

Environmental and risk assessment studies have been completed and applications for environmental clearance have been made. The public hearing for the project has been completed and "Consent to Establish" received from the Maharashtra State Pollution Control Board. Approval of the Ministry of Environment and Forests, Government of India and final clearance from the Mumbai Port Trust are awaited.

Project cost

Total project cost is estimated US $350 million

Project schedule

Financial closure is expected by December 2001 and construction completion by January 2005.

Given the credibility of the promoters, low capital costs and advantage of existing gas pipeline infrastructure of GAIL and other utilities of TPC, Indigas LNG terminal proposal is well placed to provide a reliable gas supply at a competitive price in the Mumbai region.

LNG supply

Total Fina Elf, the parent company of TGPI and one the promoters of Indigas, is among the largest LNG production and liquefaction companies in the world with significant gas reserves in the Middle East and Southeast Asia. It has equity stakes in four LNG projects in the Middle East, Viz. Abu Dhabi, Oman, Qatar and Yemen. Negotiations are at an advanced stage with two of these suppliers to meet Indigas' requirements.

Gas marketing

There are 13 major customers connected to GAIL's gas pipeline network. GAIL has not been able to fulfil its commitment to supply 14 MMSCMD of gas (3.9 MMTPA of LNG) due to shortage of gas produced from Bombay High fields. ONGC has predicted a further drop in the gas production from Bombay High due to much faster depletion of reserves. The medium term gas demand projection in the

Mumbai Region is estimated at around 10 MMTPA equivalent of LNG by the year 2005. The Indigas LNG terminal will play a crucial role in fulfilling at least 6.0 MMTPA of this demand and supporting industrial growth in the Mumbai region.

Dabhol LNG terminal

The promoters-Dabhol Power Company

The multinational company Ennron, first negotiated their fast-track power project with the state government of Maharashtra in the year 1993-94 but with a subsequent change in the ruling party, the successor state government scrapped the project in August, 1995. The project was renegotiated by Enron thereafter and whereas the abandoned approval was confined to phase I of the project, the new agreement covered both the phases I and II. Enron started construction of the 740 MW power plant representing phase I of the project in 1996 through formation of Dabhol Power Company (DPC) in which Enron initially held 80% equity. The equity structure of DPC has since changed and the share holding presently stands at Enron 65%, Maharashtra State Electricity Board (MSEB) 15% and Bechtel and GE 10% each.

DPC commissioned Phase I of the project in May, 1999 using naphtha as primary fuel. Meanwhile, construction of the bigger 1444 MW phase II was also taken in hand by DPC. Since the plants in both phases I and II are designed for using natural gas as primary fuel, DPC simultaneously started construction of a LNG terminal at Dabhol, which is a part of phase II, so as to meet gas requirements of all of its power units.

Terminal facilities

The terminal capacity is to be 5 MMTPA. A full fledged port is ready at Dabhol with a 1.8 km long jetty to receive LNG ships of 135,000 cubic metres capacity. A 2300 metres long breakwater has been provided. The marine facility has been constructed by Belgium based, Besix. The Indian construction company, Punj Lloyd, is setting up storage and regasification facilities. Three storage tanks of 160,000 cubic metres capacity each are being installed, with provision for building a fourth tank.

LNG supply

An Enron subsidiary in India, Metgas entered into an agreement with Oman-LNG in 1998 for the import of 1.26 MMTPA of LNG at Dabhol starting 2001. Later that year, Metgas signed a second agreement with Ad Gas of Abu Dhabi for a further

0.54 MMTPA of LNG. DPC's gas requirements for power generation at Dabhol will be met from these two sources.

Metgas is also reported to have signed a confirmation of intent with Malaysia LNG Tiga for the supply of 2.6 MMTPA of LNG, starting mid-2002 for the supply of gas to consumers in Maharashtra.

Project status

The LNG terminal is slated to be completed by end 2001 but its commissioning is now uncertain. Even though gas availability at Dabhol is expected to cut down the high power generation cost of DPC based on naphtha as the primary fuel in phase I, MSEB is unable to bear this high power cost resulting in its reduced power offtake and even higher unit costs due to the fixed cost component. MSEB has also expressed its inability to draw any power on the applicable terms from DPC's power units in Phase II scheduled to go in operation shortly giving rise to very serious differences between Enron and MSEB on compliance of the agreement between them. MSEB backed by the Maharashtra state and the Indian government wishes to again renegotiate the existing PPA based on the recommendations of the Godbole Committee formed by the Maharashtra government to examine the various issues. While conciliation proceedings are in progress to resolve conflicting financial claims, on May 19, 2001 DPC issued a pre-termination notice to MSEB and followed up by rescinding the PPA and stopped buying power from DPC. A six month suspension period follows which allows both parties to try and resolve their differences. On behalf of the state government the Godbole Committee has invited DPC for negotiations. Failure of talks could lead to DPC issuing a final termination notice preceded by a transfer notice transferring all facilities to MSEB and claiming penalties.

In view of the continuing impasse between the State government/MSEB and DPC, disbursement of remaining loan funds by the Indian financial institutions and banks as well as international lenders has been stopped. This will have an adverse impact on the commissioning schedules of the power plants and LNG import terminal in phase II. The prime contractor, Bechtel, (who are also equity shareholders) have also stopped work with the power plant nearly 95% complete and the LNG terminal 85% complete.

However it is highly unrealistic to expect that the project will be abandoned. Some compromise formula will eventually be reached. States other than Maharashtra will need to buy power from DPC to ensure that the plant operates at almost full capacity. If Ennore do eventually decide to pull out other power producers will be chary of taking over the project unless they are assured of evacuation of power generated at rated capacity.

Kochi LNG terminal

The Promoters

Petronet LNG Ltd.

Location of the terminal

New Vypeen island situated about 4 km north-west of Kochi Port Trust office has been selected as the site for the terminal.

The island is at the mouth of a channel where a plot of land measuring 40 hectares is to be leased to Petronet LNG Ltd by the Kochi Port Trust. The government notification of August, 2000 permitting construction of LNG terminal facilities within the Coastal Regulation Zone will be equally applicable here, as at Dahej

A 170 metres long jetty is to be built close to the terminal site. Existing draught available at the jetty head is 12 metres and will require dredging to 14.5 metres. The maritime conditions during monsoon months are not as severe as at Dahej and the tidal waves not very high. Nevertheless, 2 to 3 metres high breakwaters are to be built 800 metres towards the north and 850 metres towards the south of the island.

Terminal facilities

Initial terminal capacity is to be 2.5 MMTPA expandable to 5 MMTPA. LNG storage will consist of 2 × 110,000 cu metre tanks, with provision to add a third tank.

Project approvals

Environmental clearance has been received from Kerala State Government. In principle clearance from the Chief Controller of Explosions has been obtained. Application has still to be submitted for the all important approval from the Ministry of Environment & Forests, Government of India.

Project cost

A detailed feasibility report of Kochi terminal had been prepared by Flour Daniel/Mitsubishi. Estimated cost of the project is around Rs 16 billion ($ 350 million).

Project completion

PLL are working towards commissioning the terminal by the year 2005, though much remains to be done to attain this objective.

LNG supply

by Rasgas of Qatar.

Gas marketing

Plans for marketing of natural gas ex this terminal are being firmed up to be followed by companywise gas allocation for marketing by GAIL, IOC and BPCL.

Ennore LNG terminal

Development of the new Ennore Port

In order to meet the growing demand for power in southern region, TNEB (Tamil Nadu Electricity Board) is constructing, in stages, a new coal fired power station with an ultimate 2205 MW capacity, referred to as NCTPS (North Chennai Thermal Power Station), north of Ennore creek near Chennai. Coal is to be supplied from the Talcher coal mines in the state of Orissa, about 20 km west of the port of Paradip. Coal would move from Talcher to Paradip by rail and shipped coastally over a distance of nearly 1000 km to a new port to be developed at Ennore.

Chennai port in Tamil Nadu state is currently handling 8.5 MMTPA of coking and non-coking coal imports. In addition, 6 MMTPA to 7 MMTPA of iron ore are also presently imported. With large imports of various other products, including crude oil and petroleum products, the port capacity stands saturated. Also, dust from coal and iron ore cargoes causes air pollution. Development of a new port at Ennore, operating as a satellite to Chennai port, with two coal berths to handle thermal coal exclusively for TNEB was therefore conceived. It was subsequently decided to provide additional berths at Ennore for LNG, petroleum products, iron ore, chemicals, etc. The Tamil Nadu state government may also create a petro-chemical park adjacent to Ennore port.

Construction of the first phase of Ennore port has been funded by assistance from the Asian Development Bank and partly through investment by Chennai Port Trust and the Government of India. In the first phase, dredging of the approach channel and harbour basin, construction of 4 km long north and south breakwaters, groynes, construction of two berths for coal handling conveyor belts to NCTPS for transporting coal and development of infrastructure civil works have been carried out.

A master plan for the future development for Chennai and Ennore ports has been prepared by Grederick and Harris, consultants appointed by the ADB, consistent with the present and anticipated future growth of traffic in these ports. Chennai port is envisaged as a future potential hub for container traffic in the region and will need to meet environmental and safety provisions as it is surrounded by the densely populated city of Chennai. It is, therefore, necessary to shift other operations to Ennore port. In the subsequent phases, it is proposed to develop two more coal berths, one iron ore berth, one LNG berth, two berths for petroleum products and one chemical berth, i.e. a total of seven additional berths at Ennore port.

Ennore port has been notified by the Government of India as a major port under the Indian Ports Act 1908 and has been registered as a company, viz. Ennore Port Limited. It will be the first major corporatised port in India, setting an example to be followed by a few other ports like Paradip and Haldia. Since Ennore port will be operating on a landlord concept, the proposed facilities listed above for development in subsequent phases will be put up on BOOT or BOO basis.

LNG terminal and power plant promoters

The government of Tamil Nadu state, by its industrial development corporation, TIDCO, had invited bids, under International Competitive Bidding procedures, for a 2.5 MMTPA LNG terminal and 1850 MW capacity power plant to be located within the Ennore port area. The Dakshin Bharat Energy Consortium won this project. The consortium consists of 5 companies namely: Grasim Industries Limited (Aditya Birla Group), CMS Energy Asia Pte. Ltd., USA, Siemens Project Venture GmBH, Germany, Unocal Bharat Ltd., USA, and Woodside Energy, Australia. The consortium has registered a new company, viz. TN LNG and Power Co. Pvt. Ltd (TNLPC) to develop this project. Equity structure of TNLPC and respective responsibility of each share holder in the development process are indicated in Table 7.3.

Table 7.3 Equity structure of TNPC

Share holder	Equity share (%)	Responsibility
Grasim Industries	26.67 (US $114 million)	Co-lead developer and Lead India contact
CMS Energy	26.67 (US $114 million)	Co-lead developer Power EPC and O&M Coordinator
Siemens Project Venture	13.00 (US $55 million)	Power EPC
Unocal Bharat	18.66 (US $79 million)	LNG Terminal EPC Co-ordinator
Woodside Energy	15.00 (US $64 million)	Potential LNG supplier in second stage terminal capacity expansion

Site location

Land measuring 160 acres for the LNG terminal within the port area are to be taken on lease from Ennore Port Ltd., and 170 acres for the power plant is being acquired by TIDCO close to the port area and would be transferred to TNLPC

Terminal facilities

A jetty is to be constructed near the top end of the northern breakwater, at a distance of about 600 metres from the terminal site. Since the approach channel has been dredged only up to the south breakwater where the two coal berths have been constructed, dredging of the channel is required to be extended upto the LNG jetty. Ennore Port Ltd. has asked TNLPC to undertake the dredging at the latter's own cost and will give a set off in port charges to compensate TNLPC towards the dredging costs.

The draught in the channel will be sufficient to handle LNG tankers of 135,000 cu. metres capacity with a draught of 15.5 metres at the jetty and 16 metres at the turning circle.

LNG storage will consist of two 120,000 cu. metres tanks, with double walls and full containment. The terminal will be put up by TNLPC on BOO basis.

Power plant

The 1850 MW power plant consists of 5 units of advanced class gas turbines from Siemens, Germany operating on combined cycle mode. Construction of the power plant by TNLPC at their cost will be on BOOT basis to operate the plant for 20 years. A firm year wise tariff has been committed for 20 years for supply of power, as per their quotation under the ICB procedure.

The entire power produced will be purchased by the Power Trading Corporation (PTC) under a 20 year firm Power Purchase Agreement (PPA). The Power Grid Corporation of India Ltd. (PGCIL) will, in turn, execute transmission services agreements and back-to-back PPAs with the State Electricity Boards. PTC is likely to resell power to SEBs in the southern region follows: Tamil Nadu - 750 MW, Karnataka - 300 MW, and Kerala - 200 MW with the balance quantity of 600 MW to be decided. The ability to absorb all the power to be generated will be a key factor in the materialisation of this project.

Project cost

Approx. Rs 70 billion ($1.5 billion)

Project status

The project has received FIPB approval and CCEA approval is expected shortly. TNLPC has been permitted to bring in $426 million as foreign equity through its five share holders and a further $656 million as foreign debt thus amounting to total foreign direct investment inflow of $1082 million.

Detailed feasibility and basic design engineering studies have been undertaken and separate EPC contractors have been identified for the power plant and LNG terminal.

Applications for environmental clearance have been made after carrying out environmental and risk assessment studies. Approval of the Tamil Nadu State Pollution Control Board has since been received and clearance by the Ministry of Environment and Forests, Government of India, is awaited.

During the Indian Prime Minister's visit to USA in September 2000, a Joint Development Agreement was signed by the project developers consortium, through its shareholders, with PTC signifying Government of India's commitment to the project, support by way of payment security mechanism (PSM), and interest in achieving time bound completion. The payment security mechanism, however, is not yet in place and is reportedly causing concern to the promoters.

It is envisaged that financial closure would be achieved by March, 2002 so that project construction can start thereafter.

LNG supply

LNG will be shipped from Rasgas, Qatar, at a frequency of one ship (capacity 135,000 cu. meters) per week. Heads of agreement have been signed and Rasgas will supply LNG at a fixed price throughout the 20 years tenure of the PPA.

Gas marketing

While 1.8 MMTPA gas will be supplied to the 1850 MW power plant, 0.7 MMTPA gas is to be sold to the Madras Chemicals and Fertilizers Ltd. and other industries and consumers through short distance pipelines by setting up a separate marketing company.

Kakinada LNG terminal

Project promoters

A consortium led by Indian Oil Corporation Ltd. (IOC) is setting up a LNG import terminal and a 1000 MW power plant at Kakinada port on the east coast. The Andhra Pradesh state government has issued a letter of support to the consortium.

The "Kakinada Indian oil LNG consortium" (KIOCL) comprises IOC, Petronas of Malaysia and Cocanada Port Company Ltd. (the company operating Kakinada port at present) as partners. BP is an associate of Cocanada Port Company and has shown interest in joining the consortium.

The equity participation has yet to be decided though IOC is likely to take a major share. IOC is the dominant public sector company in the downstream petroleum sector, owning and operating a number of refineries and marketing petroleum products throughout India. It entered the LNG sector by taking an equity share in Petronet LNG Ltd. and signed a MoU with Dabhol Power Company for marketing natural gas from the LNG terminal at Dabhol. The Kakinada LNG terminal project has been promoted mainly at IOC's initiative and they will play the leading role in its execution. Andhra Pradesh state government may also take some equity through the Andhra Pradesh Power Generation Corporation.

There has been talk of separate JV companies being constituted for different project activities, i.e. for erecting the LNG terminal facilities including onshore regasification plant; shipping LNG from supply source to the terminal; laying pipeline network for gas transmission from the terminal to consumers; gas marketing; and for constructing the 1000 MW power plant.

Terminal facilities

A detailed Project Report (DPR) of the LNG terminal prepared by Tractebel of Belgium has been submitted by KIOCL to the Andhra Pradesh government in March, 2001 and comments are awaited.

The capacity of the terminal will be 2.5 MMTPA initially, expandable eventually to 10 MMTPA. The existing channel in Kakinada port is dredged to a draught of 10 metres for smaller vessels received at present. The channel can be further dredged to receive LNG ships of 135,000 cu metre capacity. The port has enough area to construct a LNG jetty with the required turning circle. No breakwater is required. Enough open government land exists adjacent to the port boundary where a suitable plot of the required size can be provided on lease by the state government. According to the central government notification of August 2000, construction of LNG terminal facilities in the CRZ is permitted.

The 1000 MW power plant

KIOCL and Andhra Pradesh state government are to agree on the vital issues of the PPA and the power rate. During preliminary meetings, the government conveyed its expectation that the power rate of KIOCL should be no higher, if not lower, than the rate quoted by promoters of Ennore LNG Terminal for supply of power from their gas based power plant to be constructed along with the LNG terminal at Ennore.

Selection of site for the power plant is expected to be taken in hand by KIOCL in consultation with the state government.

LNG supply

Discussions have been held by IOC with Petronas but no firm supply agreement has been reached so far. Negotiations with other LNG suppliers in the Far East are contemplated.

Gopalpur LNG terminal and integrated complex

The project promoters

The Al Manhal International Group (AMIG) of the United Arab Emirates, the Vavasi Oil & Gas (P) Ltd., a company of Indian technocrats, and the Industrial Promotion & Investment Corporation of Orissa Ltd; (Ipicol)–an Orissa state government undertaking, have jointly proposed to set up an ambitious integrated complex at Gopalpur port on the east coast. With an envisaged outlay of over US $ 6 billion, plans drawn up for the complex include an LNG import terminal, a large gas based power plant, a gas based urea-ammonia plant, a naphtha-cum-gas cracker along with a petrochemical plant and two long distance pipelines carrying natural gas to consumers in the northern and southern parts of the country respectively. Lately, the promoters are also considering acquisition and operation of the ships required for transporting LNG to the proposed terminal at Gopalpur.

The port

The Adani Group, which has successfully developed the Mundra port near Kandla on the west coast, has signed a MoU with Orissa state government to develop a deep water port at Gopalpur under the build-own-operate-transfer (BOOT) scheme for a concessional period of 30 years. The Adani group will be constructing solid and liquid cargo jetties after undertaking dredging and constructing breakwaters. Their help may also be sought to set up a special economic zone for industries around Gopalpur port in conjunction with the Tata group of companies, on a large land area which Tatas had acquired for an aborted steel plant project.

The LNG terminal

The Gopalpur LNG Ltd (GLL) will construct and own the LNG terminal. The equity structure of the company is reported to be on the following lines AMIG & Vasavi

(50%), Ipicol (5%), Australia LNG (25%), strategic partners (15%), and others (15%). The shareholders agreement has a built in provision for disinvestment of Ipicol's share in favour of Al Manhal-Vavasi consortium in a stipulated time frame. To be located in the Gopalpur port area, around 200 acres of land is to be acquired by GLL through the Orissa state government. Vavasi Oil & Gas (P) Ltd. are negotiating with the Adani Group for a suitable LNG jetty. LNG ships are likely to berth alongside the northen breakwater approximately 400 metres from the shoreline.

Project cost

Estimated cost is $ 450 million.

Project status

Plans for development of Gopalpur port have to be given shape before actual work can start. Since the LNG jetty is to be put up by the port developers for exclusive use of GLL, they will need to negotiate terms for developing the LNG jetty under the BOOT arrangement. Acquisition of land in the port area for construction of the LNG terminal is still to be accomplished. Consequently, the stage is not yet set for GLL to start discussing the financial arrangements to support the terminal construction and their plans to achieve the financial closure by end 2001 seems very optimistic.

LNG supply

The Al Manhal-Vavasi consortium has chosen Australia LNG (ALNG) as their LNG supplier. The consortium has signed a 'Heads of Agreement' followed by a 'Confirmation of Intent' with ALNG to secure 5 MMTPA of LNG for 20 years commencing from the year 2004. The Confirmation of Intent also provides an opportunity to ALNG to exercise an option for taking equity in GLL.

The power plant

A 2500 MW combined cycle gas based power plant is to be established with a capital outlay of $1.6 billion for which a joint venture company, viz. Gopalpur Power Ltd. has been incorporated by AMIG & Vavasi (49%) and Ipicol (51%). Land measuring 350 acres adjoining the LNG terminal has been identified for acquisition through the Orissa state government. The power is likely to be evacuated by the Power Grid Corporation of India Ltd and sold to the Power Trading Corporation.

Urea-ammonia complex

A 1.21 MMTPA gas based Urea-ammonia complex is proposed to be put up with a capital outlay of US $ 750 million through a joint venture company, viz. Gopalpur Fertiliser Ltd. Equity structure of this company is broadly: AMIG & Vavasi 51%, Ipicol 5%, and others 44%.

Petrochemicals

A naphtha-cum-gas cracker with allied downstream production facilities to manufacture petrochemicals is to be developed by a joint venture company, viz. Gopalpur Petrochemical Ltd. Indicated equity structure of this company is AMIG & Vavasi 55%, Ipicol 5%, strategic partner 20%, financial institutions 10%, and public 10%.

LNG shipping

Participation by Indian enterprises

In anticipation of the LNG shipping policy of the Government of India, promoters of LNG import terminals when inviting bids by groups of foreign shipping companies for building and operating LNG tankers, and stipulating the minimum level of equity participation the Indian shipping company must have in the JV as also making their association in the operation of the LNG tankers mandatory. Shipping Corporation of India has thus figured in both the consortiums which have successfully bid for building and operating one tanker for DPC's Dabhol terminal and two tankers for Petronet LNG Ltd. Dahej terminal.

Selection of the bid for LNG ship construction and operation for Dahej terminal was decided by Petronet LNG Ltd. out of three short listed offers. The unsuccessful offers made by two consortiums included the Indian companies, Great Eastern Shipping and Indian Oil Corporation in one case and Essar Shipping in the other. In view of the large capital investment required, the number of Indian companies expected to participate in the bidding consortiums for LNG tankers will be limited.

Shipping requirements

For the four LNG import terminals which may progressively get commissioned by 2005, viz Dabhol (5 MMTPA), Dahej (5 MMTPA), Hazira (5 MMTPA) and Trombay (3 MMTPA), a total of eight to nine LNG tankers is required to transport LNG supplies from different supply sources to feed these terminals if they operate at their full capacities. While these tankers will be of standard large size of around 135,000 cubic metres, one or two tankers for Trombay terminal need to be of smaller

100,000 cubic metre capacity to suit the lower draught of 9.5 metres available at the jetty head at Trombay.

Additional LNG tankers will need to be put in operation beyond the year 2005, as more import terminals are put up at Kochi (2.5 MMTPA), Jamnagar (say 5 MMTPA), Kakinada (2.5 MMTPA), Pipavav (3 MMTPA), and Gopalpur (5 MMTPA). The Heads of Agreement entered into with Rasgas for supply of LNG to Ennore import terminal being on cif basis, shipping arrangement from Qatar to Ennore will be the responsibility of Rasgas. Since acceptance of this quotation while deciding on the successful IBC bidder is an old commitment, the government is likely to let the arrangement stand notwithstanding the LNG transportation policy presently under finalisation.

Shipping arrangements under negotiation

The following arrangements have been made so far:

Dabhol

Following a US $ 200 million joint venture agreement concluded in December 1998 between Ennron (20%), Mitsui OSK Lines (70%) and Shipping Corporation of India (10%) for the construction of one 135,000 cubic metre LNG tanker, a JV company, viz. Greenfield Holding Company Ltd (GHCL) was formed. The tanker named `SS Laxmi' is under construction in Nagasaki harbour in Japan and scheduled to be ready by end 2001. However, till the serious differences between DPC and Maharashtra state government/MSEB are resolved, the tanker may have to be spot chartered. Furthermore, the daily charter hire of $98,000 for the vessel agreed by DPC with GHCL is under question, since it is much higher than the daily charter hire of $ 68,900 recently settled by Petronet LNG Ltd for two LNG tankers of 135,000 cubic metres capacity each to be built by a consortium having two partners in common with GHCL, to transport LNG from Qatar to the Dahej terminal.

Dahej

Petronet LNG Ltd. has selected the consortium of Mitsui OSK Lines (34%), Shipping Corporation of India (34%), Kawasaki Shipping and NYR (both sharing 32%) for the $316 million contract to build and operate two 135,000 cubic metres capacity LNG tankers on daily charter hire basis. The consortium had bid a fixed daily rate of $57,900 and a variable cost of $11,000 with cost escalation linked to the US consumer price index. Both vessels are expected to be operational in 2004.

Hazira

The Shell group has placed orders with Mitsubishi Heavy Industries Japan and Daewoo Shipbuilding and Marine Engineering, South Korea, for construction of two 135,000 cubic metres capacity vessels to add to their existing international fleet and two other LNG tankers also an order. Structuring of ownership and operation of the tankers meant for Hazira will be decided after the government policy is formally declared.

Shipping arrangements contemplated

Trombay

Total Fina Elf are likely order one LNG tanker of 100,000 cubic metres capacity after they obtain the all important environmental approval to their Trombay LNG terminal by the Ministry of Environment & Forests, Government of India

Gopalpur

Two LNG ships are proposed to be acquired. Formation of a joint venture shipping company is under negotiation. Besides the Al Manhal-Vavasi consortium, shares are expected to be held by North-West Shipping Corporation (the shipping arm of Australia LNG) and Shipping Corporation of India.

Outlook -LNG import terminal projects

Though the progress in the development of LNG import terminals has been slow, the first terminal in India of DPC at Dabhol will be mechanically complete by end 2001, but its commissioning is now very uncertain. In any case its operation will initially be limited to DPC's own gas requirement, as transportation arrangements are not in place for DPC to market the surplus LNG after regasification to other consumers.

All statutory approvals for construction of the LNG import terminals at Dahej and Hazira of 5 MMTPA capacity each are in hand. The EPC contractors have been selected and construction work will start post 2001 monsoons or financial closure, whichever is later.

The remaining environmental approval from the Ministry of Environment & Forests, Government of India for the 3 MMTPA capacity LNG import terminal at Trombay is under active consideration of the Ministry and the EPC bids will be issued soon after the approval is received.

It is reasonable to expect that an import capability of 18 MMTPA of LNG will be available by the year 2005. The absorption of the entire output of these terminals is a matter of some concern as all are located to feed only the western and northwestern regions of India. Though the capacity of the HBJ pipeline is to be expanded to 60 MMSCMD, equivalent to 16 MMTPA of LNG (see Chapter 8), it will still be handling a fair quantity of gas from the Western offshore fields. Therefore development of networks and markets in Gujarat and Maharashtra (and along the route of the HBJ pipeline) need to be accorded a high priority. Even then the terminals may not be able to operate at full capacity in 2005 as the projected all-India import requirement in 2005 is only around 10 MMT. (Chapter 6). A detailed examination, which is beyond the scope of the present study is, therefore, very necessary.

Meanwhile, the prospects of the proposed gas pipelines from Bangladesh and Iran will become clearer so as to enable a rational determination of the quantum of additional LNG import capacity required. Promoters of the proposed terminals at Kakinada (2.5 MMTPA), Gopalpur (5 MMTPA) Jamnagar (5 MMTPA) and Pipavav (3 MMTPA) will need to proceed cautiously while firming up their plans and proposed plant capacities and also take into account development of offshore discoveries especially on the eastern seaboard.

Nonetheless, it would appear that gas import capability of the order of 30 MMTPA may well progressively develop by the year 2015 to meet the import requirement of 27 MMT projected in Chapter 6.

8

Gas transmission infrastructure

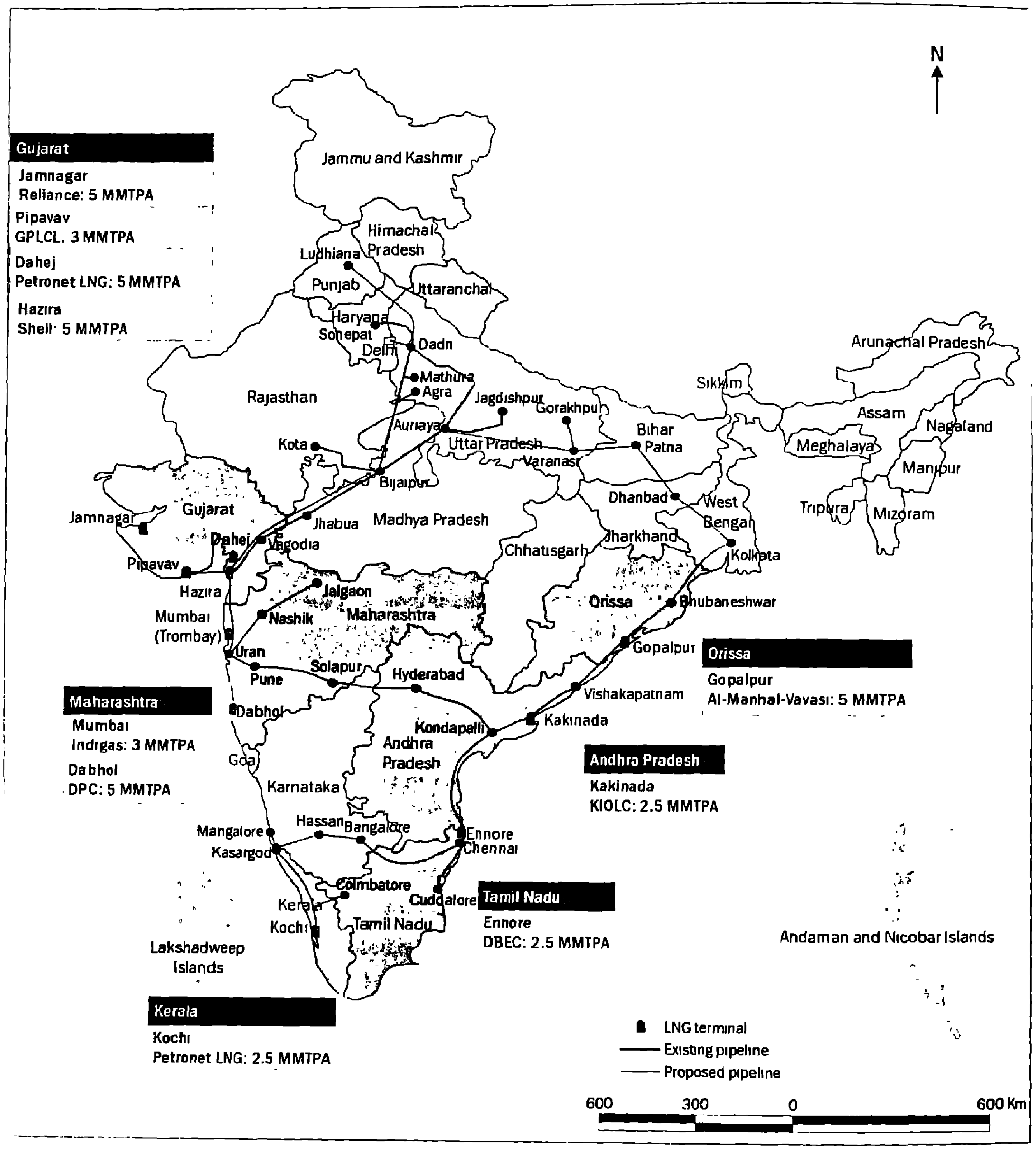
Currently GAIL is the only major gas transmission company operating in India. While there is no bar to other transmission companies setting up shop in India, GAIL has been able to maintain a near monopoly as it is contracted with ONGC to evacuate the latter's gas production and meet consumers requirements. With the setting up of LNG terminals and the possibility of imported piped gas, there is obviously a need for a much larger and integrated gas grid than what exists today. To enable gas to be moved to inland consumption centers gas pipelines will need to be constructed in phases and in tandem with the construction of the LNG terminals and new user plants and facilities. GAIL would no doubt wish to maintain its pre-eminence in this field especially as it is also a stakeholder in Petronet LNG which is setting up two terminals at Dahej and Kochi.

In this chapter, the major gas transmission proposals are described in the context of the evacuation of regasified LNG from each of the proposed terminals, augmentation of local area networks and the import of piped gas. The alignments of these pipeline proposals are illustrated in Figure 8.1.

Jamnagar LNG terminal

No substantial demand for natural gas presently exists in the vicinity of Jamnagar. Of the three other proposals for LNG terminals in Gujarat state at Hazira, Dahej and Pipavav, the first two are located close to the existing pipeline network feeding parts of Gujarat State and the long distance HBJ pipeline carrying gas up north. Reliance does not want to bank on the same infrastructure by hooking up their proposed Jamnagar terminal with the HBJ pipeline at Vagodia by a 300 km pipeline. It is therefore examining the possibility of laying two parallel pipelines, one connecting the terminal in Jamnagar to Cuttack in Orissa where they have an offshore exploration block and another connecting Goa with Kakinada in Andhra Pradesh they have offshore exploration blocks at both places. Spur lines will be laid from these two pipelines to meet demand right across the central belt of India.

Figure 8.1. Existing and proposed gas transmission network



Pipavav, Dahej and Hazira LNG terminals

All three terminals are planning to meet the demand in Gujarat through the existing local area networks, which are to be considerably expanded, and to supply north-western and northern India through the HBJ pipeline. While the Dahej terminal is located close to Hazira, a sub-sea pipeline would need to be laid from Pipavav to Hazira.

Gujarat state network

The Gujarat government had framed a Gas Act in 2000 to regulate transmission and distribution of natural gas in the state. The state-owned company, Gujarat State Petronet Ltd (GSPL), was to be the sole agency to create a network of 1,500 km pipelines for transporting indigenous and imported gas to major consumer centres in Gujarat at a planned investment of Rs 24 billion ($ 520 million) and to operate it on a 'common carrier' basis. However, arising from an objection by the Ministry of Petroleum and Natural Gas, the Gujarat Gas Act was amended and exclusive powers of GSPL to provide a pipeline in the state withdrawn.

The Gujarat government has a plan to offer equity shares in GSPL to major players which has changed over time. Currently it is reported that a total of 35% equity would be offered to major LNG suppliers and users (with a minimum 4% equity stake and a cap of 11%), 40% to 3 state government entities, 11% to GAIL and the balance 14% to financial institutions. It is understood that Shell, Gaz de France and British Gas have accepted the offer of participating in GSPL's equity by committing $13 million each for a 11% share..

The project itself is to be executed in two phase. Phase I consists in laying a pipeline from the Gujarat and Maharashtra border to Vadnagar in North Gujarat for a total length of 525 km to be completed in 2002. Phase II would involve laying pipelines in the Saurashtra region for a total length of 600 km, to be completed in 2005.

Meanwhile, the GSPL has commenced the construction of a gas pipeline network in South Gujarat of total length 98 km to connect with the existing 70 km pipeline, of Gujarat Gas Co. Ltd (a subsidiary of British Gas) to evacuate gas from the Hazira fields of the GSPC. This network would connect Hazira to Dahej. It would also provide gas to the 655 MW Gujarat PowerGen Energy Corporation (GPEL) power station at Paguthan now owned by CLP-IP, Hong Kong and Gujarat Electricity Board's power station at Utran. The total cost of the project while includes a compressor at Hazira is estimated at Rs 2 billion ($ 43 million).

Hazira-Bijaipur-Jagdishpur (HBJ) pipeline

The HBJ pipeline, is the only major gas transmission line in India. It is owned by GAIL and was commissioned in 1986-97, essentially to supply fertiliser plants and power plants in Madhya Pradesh and Uttar Pradesh. The pipeline was built in 22 months by a consortium (Messers Spie-Capag of France, Nippon K K and Toyo Engineering of Japan), at a cost of Rs 17.5 billion in 22 months. Further expansion of the network to customers in Gujarat, Rajasthan, Haryana and Delhi took place in a phased manner. Facilities for extraction of LPG and C5+ fractions have been built along the 2300 km length of the pipeline.

Wet gas from the offshore South Bassein field is fed by 216 km sub-sea lines of 36" & 42" dia to ONGC's sweetening and fractional separation plant at Hazira. In 1997-98 ONGC initiated the South Bassein booster compressor platform project for sustaining a supply of 30 MMSCMD of gas to Hazira. The inland pressure at the South Bassein platform is around 1950 psi and delivery at Hazira is 850 psi. Apart from separation of LPG, (approx. 500,000 MTPA) ONGC have commissioned a kerosene recovery plant at Hazira for the production of NGLs, Kerosene and aromatic rich naphtha. The gas handling capacity of the Hazira terminal has also been expanded from 20 MMSCMD to 41 MMSCMD.

A map of the HBJ pipeline is provided in Figure 8.2. It consists of a 36" line from Hazira to Bijaipur (Vijaipur) which thereafter reduces to 30" with further reduction beyond Auraiya. Spur lines at various points in Gujarat, Rajasthan, Uttar Pradesh, Delhi etc. feed power plants, fertiliser plants and industries. Originally the capacity of the line was 18.2 MMSCMD with compressor stations at Jhabua and Vaghodia boosting the pressure from 780 psi to 1200 psi. The completion of the Gujarat Rehabilitation and Expansion Project (GREP) which involved laying a 505 km x 30" tie-line between Bijaipur and Dadri along with enhancement of compressor capacity at Hazira and Jhabua and additional compressors at Vaghodia and Khera, resulted in an expansion of capacity to 33.4 MMSCMD.

Apart from gas transmission, GAIL has built the following plants along the route of the pipeline (Tables 8.1 and 8.2).

Table 8.1 LPG recovery plants

Year of commissioning	Location	Capacity (TPA)
1990-91	Bijaipur I	203,000
1991-92	Bijaipur II	203,000
1992-93	Vagaodia	73,000
1999-00	Auraiya	258,250
Total		737,250

Figure 8.2. HBJ (Hazira-Bijaipur-Jagdishpur) gas transmission system

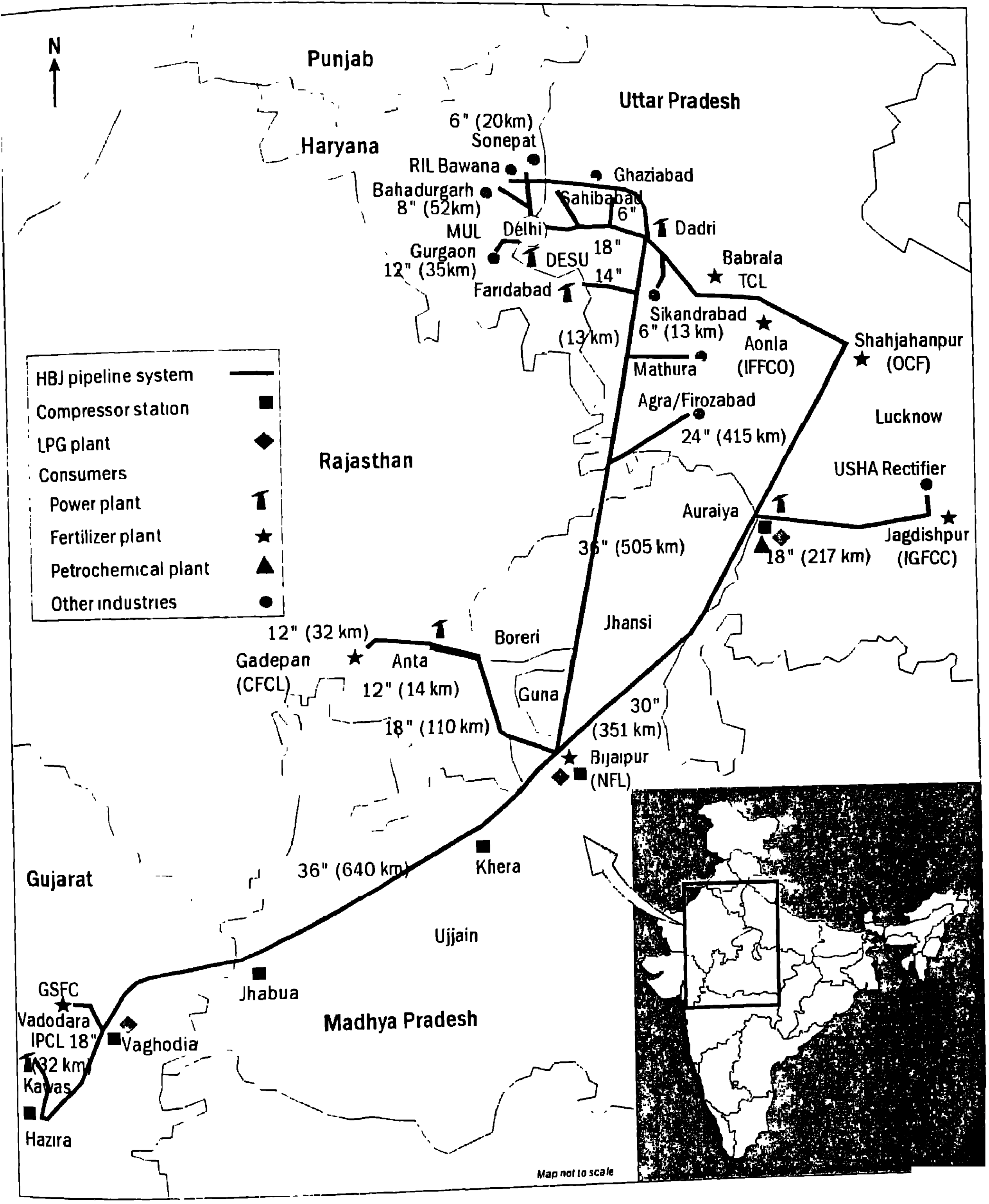


Table 8.2 Liquid fractions and propane recovery plants

Year	Location	Capacity (TPA)
1993-94	Bijaipur (Industrial solvents propane & pentane)	100,000
1995-96	Bijaipur (Propane)	65, 000

In 1998/99 GAIL commissioned a petrochemical plant at Pata near Auraiya in UP's district of Etawah. The plant has been designed for a feed of 11.6 MMSCMD rich gas and 9.7 MMSCMD lean gas to a gas cracker with a capacity of 300,000 MTPA of ethylene and 12,000 MTPA of propylene. Further processing of these intermediates will yieldLLDPE/HDPE (160,000 MTPA swing facility), HDPE (100,000 MTPA), and Butane (10,000 MTPA).

To cater to LNG imports, considerable expansion and strengthening of the HBJ pipeline will be required. GAIL proposes to invest around Rs 30 billion ($ 650 million) to expand its capacity to 60.0 MMSCMD by 2003 by, inter alia, laying a parallel line from Hazira to Bijaipur. A detailed feasibility report of the project has been completed. GAIL is also planning to extend the HBJ pipeline to Ludhiana to cater to the requirements of Punjab and Haryana.

Absorption of the regasified LNG may pose technical problems, as lean gas injected into the wet gas system will affect the capacity of the various LPG and liquid fraction extraction plants along the HBJ pipeline. There appear to be two options, not mutually exclusive, for GAIL to surmount this problem:

- To supply regasified LNG to customers on the local Hazira network and divert the wet gas currently supplied to the HBJ pipeline.
- To use the proposed parallel line from Hazira to Bijaipur and the tie line from Bijaipur to Dadri exclusively for regasified LNG, keeping the original HBJ pipeline for wet gas from South Bassein.

Another issue that GAIL will need to address is the declining output of gas from fields supplying the North and South Gujarat networks. An inter-connection between high volume customers on these networks to the HBJ will be required at a future date. (GSFC Baroda is presently connected to both the South Gujarat and the HBJ networks). Similarly the projected decline in the supply of Western Offshore gas to Uran can be augmented by reversing the flow in one of the two sub-sea pipelines that connect the Western Offshore fields to Hazira and supplying regasified LNG from Hazira to the network that is fed from the Uran terminal.

Trombay and Dabhol LNG terminals

Apart from meeting the gas demand of the Tata Power Company at Trombay, Indigas will satisfy the current and projected shortfall in gas production from Bombay High that is currently supplied to the Uran terminal.

Maharashtra state network

GAIL has signed a gas cooperation agreement with the Maharashtra Industrial Development Corporation and the Maharashtra Petrochemical Corporation Ltd for the development of a gas pipeline network and marketing of natural gas in the state. A joint working group will determine the potential gas demand and the contours of the gas supply infrastructure which could extend from Mumbai to Solapur via Thane and Pune, and another branch to Nashik, Aurangabad and Jalgaon. The length of the network is estimated at 1300 km and requires an investment of over Rs 25 billion ($ 540 million). Conceptually the pipeline could also be extended from Solapur to Hyderabad in Andhra Pradesh linking up with the proposed eastern grid.

Enron's plans for gas marketing from Dabhol terminal

While deciding to put up a large LNG import terminal of 5 MMTPA capacity at Dabhol, Enron had planned to market around 3 MMTPA of surplus regasified LNG after meeting DPC's requirement of 2 MMTPA for power generation. They floated a subsidiary company, Metgas for the purpose of gas marketing and transportation with an initial investment of $ 60 million. Metgas made offers of gas supply to consumers in the states of Maharasthra and Gujarat who have not been able to get their full requirements of natural gas from GAIL and signed MoUs with some of them. Metgas planned to lay a pipeline from the Dabhol terminal towards Mumbai parallel to the west coast and further to the industrial centres in western part of Gujarat State. Enron also announced a tie-up with IOC for gas marketing from the Dabhol terminal.

The imbroglio over the Dhabol power plant brought all work is a standstill and Metgas staff, who were mainly on land survey work, were asked to resign. Considering that work on the 5 MMTPA terminal is almost complete, this facility will ultimately be commissioned but its ownership may well be in other hands

Kochi LNG terminal

Kerala state network

GAIL and the Kerala State Industrial Development Corporation (KSIDC) have entered into a gas cooperation agreement for the development of a gas pipeline network and marketing of natural gas in Kerala. A joint working group is to evaluate the potential consumers, the aggregate demand and the pipeline infrastructure. KSIDC is to assist GAIL in the techno-economic study and co-ordinate the grant of all necessary clearances, so as to have the facilities ready by 2004/2005 to evacuate regasified LNG from the Kochi terminal.

Demand for gas in Kerala is likely to be relatively low and GAIL would need to look further afield to be able to absorb the entire regasified LNG from this terminal. Therefore, GAIL is also planning the expansion of their network into Karnataka.

Karnataka state network

GAIL has signed an agreement with the Karnataka State Industrial and Infrastructure Development Corp (KSIIDC) to study the setting up a gas pipeline to serve various end users in Karnataka. As in the case of Kerala a joint working group is to conduct a techno-economic feasibility and develop specifications for the proposed gas infrastructure. Tentative plans are to lay a pipeline from Kochi along the coast to Kasargode in Karnataka where it will bifurcate. One arm will extend to the port of Mangalore and the other to Bangalore. An investment of Rs 20 billion ($ 435 million) would be required for the 1000-km pipeline network and other facilities. Initially, the system would handle about 5 MMSCMD rising to 20 MMSCMD. At a later stage, the pipeline will be extended to Mysore. GAIL is also planning to lay a 570 km LPG pipeline from Mangalore, where HPCL have an import terminal, to Mysore and Bangalore and further south in Coimbatore at a cost of Rs 6 billion ($ 130 million). A feasibility study for the project has been completed. There are obvious synergies to be obtained if the pipelines for regasified LNG and LPG can be constructed simultaneously using a common right-of-way for a major portion of the two networks.

Ennore LNG terminal

As mentioned in Chapter 7, the 2.5 MMTPA LNG terminal will essentially meet the requirements of the 1850 MW power plant at Ennore with only about 28% of the regasified LNG being sold to industries and consumers through a local area network. Therefore, there are no plans to set up a transmission pipeline out of Ennore.

Kakinada LNG terminal

It is early days yet to speculate on the requirement of a gas transmission pipeline. However, the promoters will need to monitor GAIL's plans for expansion of their existing network which is supplied from the offshore Ravva should the need arise to distribute regasified LNG other than in the vicinity of the terminal.

Andhra Pradesh state network

GAIL is planning to market 13.5 MMSCMD of gas by 2002/03, to mostly private power projects in East Godavary, West Godavary, and Krishna districts of Andhra Pradesh. GAIL is currently supplying 3 MMSCMD of natural gas to 550 MW of power generation capacity in the state. GAIL will complete the Rs 6 billion Phase II and III of the Krishna-Godavary basin gas distribution network comprising 413-km gas pipelines by June 2002, the first phase of 135-km gas pipeline having already been commissioned at an estimated cost of Rs 1.1 billion ($ 24 million). Construction on the second phase of the project comprising 209 km is scheduled to be completed by June 2001 at an estimated cost of Rs 2.9 billion ($ 63 million). The third phase of 204 km entails an investment of Rs 3 billion ($ 65 million). Plans include the laying of a gas pipeline from Narsapur to Kondapally. GAIL has also entered into a MoU with the Andhra Pradesh Industrial Infrastructure Corporation Ltd (APIIC) to supply piped natural gas to domestic and commercial consumers under the Town Gas Supply Scheme in the state.

Andhra Pradesh has been allocated 5 MMSCMD of gas and will get another 7 MMSCMD after the completion of the gas pipeline projects.

Gopalpur LNG terminal

The Al Manhal International Group (AMIG) of the UAE and the Indian company Vavasi Oil and Gas (P) Ltd., the promoters of the LNG terminal at Gopalpur, have maintained a low profile in pursuing their LNG terminal proposal and their very ambitious transmission network. Though not much is known about these two companies in India, they may well turn out to be dark horses to set up a terminal and related transmission infrastructure in India. Two long distance gas pipelines are proposed to be established.

Gopalpur-Cuddalore pipeline

This pipeline is projected to run 1250 km southwards, from Gopalpur to Cuddalore, parallel to the eastern coast linking the state of Andhra Pradesh to Tamilnadu and Karnataka. It will have a spur nearly 300 km long to Hyderabad and another spur of 350 km to Bangalore.

Gopalpur-Kolkata-Auraiya pipeline

The second pipeline, over a similar length of 1250 km, will connect Gopalpur with Kolkata in West Bengal and traverse through the states of West Bengal, Jharkhand, Bihar and Uttar Pradesh, linking up with the HBJ pipeline at Auraiya.

The AMIG-Vavasi consortium has entered into a MoU with the UP State Industrial Development Corporation (UPSIDC) offering gas supplies to industries at a number of important locations including a proposed gas cracker. Similar MoUs have also been signed by UPSIDC with Unocal and Shell.

Development of the two gas pipelines is to be done through a joint venture company, Natural Gas Pipeline Ltd, with the following equity structure : AMIG & Vavasi (51%), Ipicol (5%), financial institutions/banks (15%), state government nominee (11%), and public (18%).

The plans to lay the pipeline to UP via Kolkata is also to stake a claim for transmitting imported Bangladeshi gas should the source materialise sometime in the future. With Unocal and Shell also planning to bring gas from Bangladesh to India, an agreement between these companies and possibly GAIL also, would be necessary so that a single line can be constructed to the markets in North India eventually linking up with the HBJ pipeline.

All-India gas grid

Considering the current development status of each of the LNG terminal and import pipeline proposals, the location of markets and the relative economics of the various fuels, it is anticipated that the networks will be developed in three phases as follows:

Phase I (by 2005)

- Gujarat state network - Phase 1
- HBJ pipeline expansion
- Andhra Pradesh state network

Phase II (by 2007)

- Gujarat state network - Phase 2
- Maharashtra state network
- Kerala state network
- Karnataka state network - Phase 1
- Gopalpur - Cuddalore pipeline

Phase III (between 2008 and 2015)

- Karnataka state network - Phase 2
- Gopalpur - Kolkata - Auraiya pipeline

From the map in Figure 8.1 it will be seen that though the various gas transmission pipelines are being proposed and planned independently, if they all materialise India will have a gas grid connecting the northern, southern, eastern and western regions of the country by 2015. The HBJ pipeline measures 2300 km and additions to the network of about 5700 km is envisaged, making a total length of 8000 km.

9

Environmental considerations

Pollution of air, water and land has increased significantly over the years. Industrial and vehicular pollution abatement deserves a high priority for India. While India's gross domestic product (GDP) has increased 2.5 times over the past two decades, vehicular pollution has increased eight times and pollution from industries has quadrupled. Natural gas stands out as a superior fuel in many aspects. The use of natural gas in industrial sector, especially power, and transportation sector will reduce air emissions. Also, the problem of fly ash would be solved.

Collective action by the government, judiciary, public, non-governmental organisations (NGOs) and industries is required to lead the economy towards the path of sustainable development. The Ministry of Environment and Forests (MoEF) in the Central government and similarly named ministries in the state governments are the principal nodal agencies for all environment-related matters. MoEF is responsible for providing environmental clearance for all major projects in the public and private sector on the basis of a review of the Environmental Impact Assessment (EIA) reports and through its regional offices for monitoring compliance with conditions attached to such clearances. The basic executive authority under the environmental laws is vested in the Central Pollution Control Board (CPCB), the State Pollution Control Boards (SPCBs) and the Pollution Control Committees of the Union Territories. The mandate of the CPCB is to set environmental standards and co-ordinate the activities SPCBs. The implementation of environmental laws and their enforcement are the responsibility of the SPCBs.

Several NGOs like TERI, Centre for Science and Environment, People's Commission on Environment and Development India, etc., study the relationship between environment and development and also create public consciousness about the need for sustainable development. There is an increase in the number of public interest litigation's (PILs) filed by the public and NGOs over the last few years. A series of writ petitions have been filed by environmentalists in the High Courts and in the Supreme Court against ineffective action on the part of the government in protecting the environment. On the basis of extensive hearings, the courts have issued a wide range of directives to various authorities.

In India, the ambient air quality standards have been established by adapting standards/criteria developed in the western countries, to suit local conditions. A comparison between quality standards set by various organizations and the standards in India is given in Annexure 9.1.

Power sector

Coal is a major fuel for power generation in India. The quality of indigenous coal supplied to power plants varies widely but generally Indian coal has high ash, low sulphur and low heating value. In general, inferior grades of non-cooking coal are used for power generation in the country. The properties of coal used for power generation are given below:

1. Mineral matter (ash) content on "as received basis" is in the range of 27% to 42%.
2. Moisture content on "as received basis" ranges from 7 to 20%.
3. Volatile matter content ranges from 20-30%.
4. Gross calorific values (GCV) range from 3200 kcal/kg to 4800 kcal/kg.
5. Hard Grove Index values are more than 45 and thus the coals are easy to grind and size.
6. Sulphur content is generally very low (<1%).
7. Nitrogen content is generally low (<1%).

Air emissions

In India, the CPCB has prescribed emission standards for particulate matter and gaseous pollutants from thermal power plants (Annexure 9.2). The CPCB has not yet fixed any emission standards for SO_2, but it has prescribed stack height norms. For NO_x emissions, CPCB is in the process of formulating appropriate standards for coal-based plants. However, CPCB has already prescribed standards for NO_x emissions for natural gas and naphtha based thermal power plants.

The annual emissions from a typical power plant (500 MW) using different fuels are given in Table 9. 1.

Table 9.1 Annual emissions from a typical power plant (500MW) using different fuels

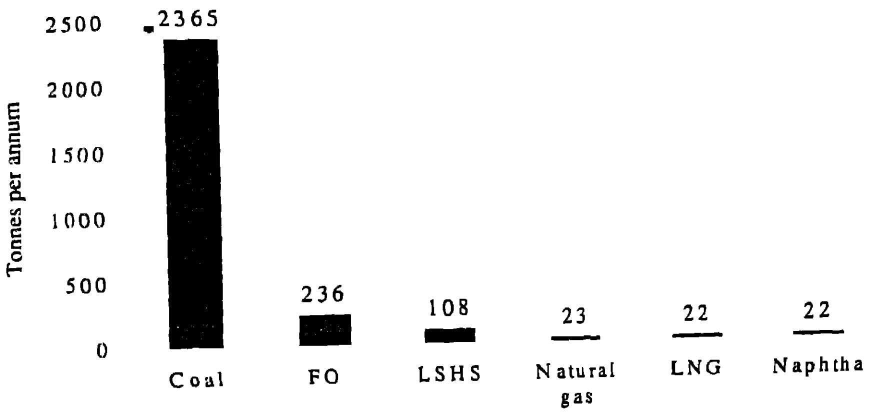
Fuel	Total fuel consumed (tonnes)	Emission factor source	SPM (tonnes)		SO_2 (tonnes)	NO_x (tonnes)
			Uncontrolled[1]	Controlled[2]		
Coal	1971000	CPCB	630720	2365	11452	5203
LSHS (Oil)	743036	WHO93*	1082	108	11889	3938
Fuel Oil (High S)	743036	WHO93	2357	236	31208	3938
Natural gas	383199	WHO93	23	--	77	1680
LNG	358208	WHO93	22	--	0	1570
Naphtha	364548	WHO93	22	--	124	1598

*WHO93: World Health Organisation, 1993

[1] ESP not installed; [2] ESP installed

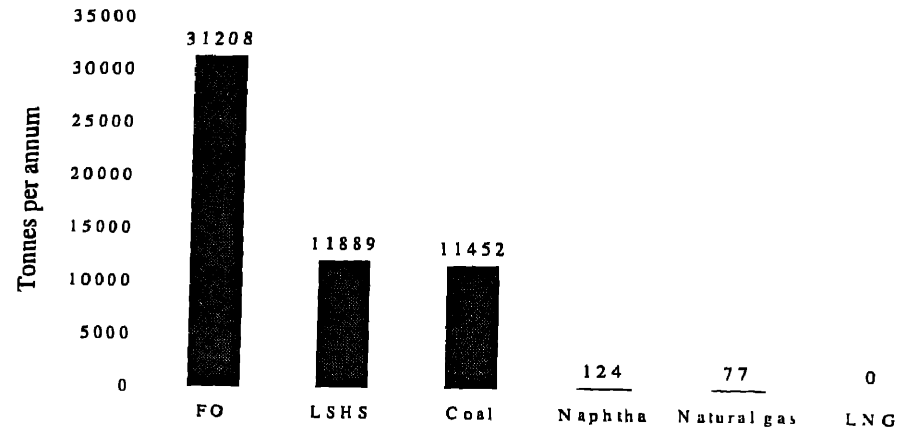
Figure 9.1 ranks the annual SPM emissions from a 500 MW power plant based on different fuels. The bulk of coal based generating capacity in India consists of units of 210 MW and 500 MW. All these units are based on sub-critical pulverised coal technology and utilise high ash (35-40%) and low grade (4000 kcal/kg GCV) coal, resulting in high levels of particulate emission. Though these plants are provided with Electrostatic Precipitators (ESPs), their performance has been affected by high resistivity ash and unburnt carbon particles.

Figure 9.1 Annual SPM emissions



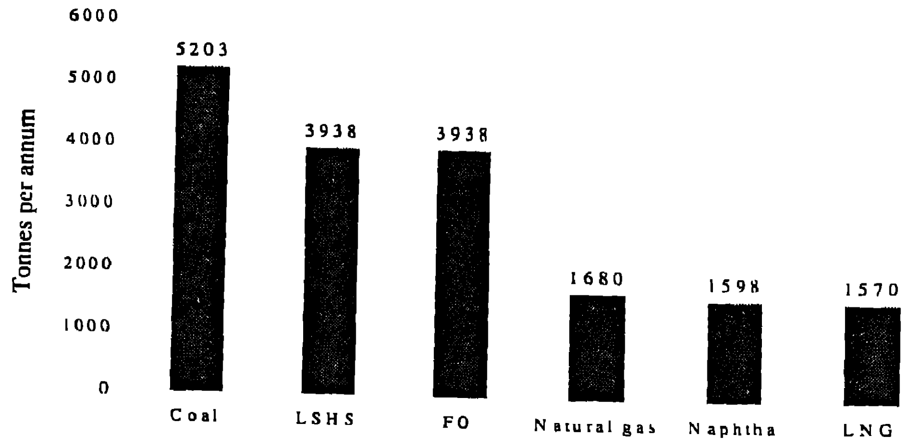
Indian coals in general have a low sulphur content. As per CPCB guidelines, adequate SO_2 control measures are mandatory if the sulphur content of the fossil fuel for power generation exceeds 2%. Figure 9.2 ranks the annual SO_2 emissions. The cleanest fuels in respect of SO_2 emissions are LNG, natural gas and naphtha.

Figure 9.2 Annual SO_2 emissions



Annual NO_x emissions from a 500 MW power plant using different fuels are ranked in Figure 9.3. The cleanest fuels in respect of NO_x emissions are LNG, naphtha and natural gas.

Figure 9.3 Annual NO_x emissions



Constant monitoring of coal-based plants by CPCB and SPCBs has shown that, by and large, concentration of SO_2 discharged into the air is well under control. However, SPM emissions have been found to exceed the norms.

Finally, carbon dioxide emissions are reduced when natural gas is used as a fuel. Carbon dioxide emissions are 0.96 million tonnes per annum from a 500 MW powe plant when natural gas (emission factor: 56100 grams/Giga joules energy input) is used as a fuel, compared to with 3.12 million tonnes per annum from a coal-based (emission factor: 56100 g/GJ energy input) power plant.

Solid waste

Ash residues and the dust removed from exhaust gases may contain significant levels of heavy metals and some organic compounds in addition to inert materials. Fly ash removed from exhaust gases makes up to 80% of the coal ash residue in pulverised coal boilers. The balance 20% is bottom ash, which includes slag and coarser, heavier particles.

In 1999, 58 million tonnes fly ash was generated by coal based thermal power plants in India. For a 500 MW power plant using indigenous coal (40% ash) approximately 0.76 million tonnes of ash (0.6 million tonnes of Fly ash + 0.16 million tonnes of Bottom ash) is generated annually which is presently discharged into ash ponds. Therefore, disposal of fly ash and bottom ash is extremely water and land intensive. It causes diversion of fertile lands for ash ponds and unsustainable water usage. Disposal of fly ash is expensive and the cost is estimated to be about 2% of the operating cost of the power plant. The Ministry of Environment and Forests, Government of India, has stipulated that all new coal-based power plants should indicate a plan for utilization of the ash while submitting the Environmental Impact Assessment (EIA) / Environment Management Plan (EMP) for approval.

Waste water

CPCB has prescribed a set of guidelines for effluent discharge from various sources, namely, condenser cooling water, boiler blowdowns, cooling tower blowdowns and ash pond effluent from thermal power plants (Annexure 9.3). All the effluents must be neutralized and treated before being discharged into waterways or drains. CPCB standards when compared with World Bank guidelines show that standards are comparable for zinc and iron. In case of all other parameters, CPCB standards are less stringent.

Thus, it is observed that coal as a fuel in thermal power plants results in pollution of air, water and land. Proper control devices and waste water treatment will result in reduction in the quantities of carbon dioxide, oxides of nitrogen, sulphur dioxide, particulate emissions and toxicants being discharged in effluents. Commercial utilization of fly-ash provides a viable solution for disposal of solid waste. Also, the use of cleaner fuels like natural gas can go a long way in achieving the twin objective of power generation and environmental protection.

Industry

Industries contribute to environmental pollution by way of air emissions, liquid effluents discharged into water and solid wastes. CPCB conducted a survey of industries in 1991. On the basis of this survey, the government has identified 17 categories of industries as highly polluting industries for monitoring and regulating air and water pollution. These industries are: aluminium, caustic, cement, copper, distillery, dyes and dye intermediates, fertilizer, iron and steel, leather, pesticides, petrochemicals, pharmaceutical, pulp and paper, refinery, sugar, thermal power plants and zinc industry. MoEF has developed standards for regulating emissions from various industries. These emission standards for selected industries are given in Annexure 9.4. Discharges of industrial effluents are regulated through Indian Standard Codes.

Industrial growth has been accompanied by a variety of environmental problems. Whereas industrial output grew fourfold between 1963 and 1991, toxic releases grew by about six times. Emissions from industries vary, as there is a wide range of fuel types and industrial processes used. However, the important pollutants from industries are SPM, carbon monoxide, sulphur dioxide and oxides of nitrogen. Table 9.2 gives the percentage contribution of different industries to pollution, as given by World Bank, 1996. Adequate pollution control devices need to be installed to control the air emissions. According to CPCB 1995 report, out of 1551 large and medium sized units falling in the category of highly polluting industries, 1125 units have installed pollution control facilities. Also, air emissions would be reduced by switching to cleaner fuels like natural gas.

Table 9.2 Contribution of industries to pollution

Sector	Share of total pollution (%)		
	Particulate	Sulphur	Nitrogen
Industrial chemicals	8	11	15
Iron and steel	23	2	5
Non-ferrous metals	3	1	0
Other chemicals	1	0	1
Food products	11	4	8
Paper and pulp products	4	15	11
Non-metallic mineral products	32	3	10
Petroleum refineries	6	31	21
Textiles	6	30	23

Source: World Bank (1996)

However, India has over 3 million small-scale units, which account for over 40% of the total industrial output in the country. These units are financially and technically less equipped to install pollution control devices. Major air polluting small-scale industries are foundries, chemical manufacturing and brick-manufacturing.

Case Study: Agra and Firozabad

Switching to clean fuels is clearly the best alternative to reduce the pollution caused by industries. This case study illustrates the initiatives taken by government to persuade the industiral sector in Agra and Firozabad to substitute natural gas for coke/coal as a fuel and the subsequent impediments faced in the process of conversion.

In response to a Public Interest Litigation seeking protection of Taj Mahal from environmental pollution, the Supreme Court passed the landmark judgement on December 30th, 1996, banning the use of coke/coal in all industries located within the Taj Trapezium Zone (TTZ) - an area of 10,400 sq. km around Taj Mahal. The foundry industry cluster at Agra stands out as the most significant industry sector in terms of total number, high energy intensity and air pollution. Of the 136 operating foundry units, 111 units are in the 'gas zone' and the remaining in the 'no gas zone', as defined by the Gas Authority of India Limited (GAIL). All the units located in the gas zone have applied for gas. In Firozabad glass industry sector, 194 units are in the 'gas zone' and 107 units are in the 'no gas zone'. Natural gas to Agra and Firozabad has been brought by upgrading the Hazira-Bijaipur-Jagdishpur (HBJ) pipeline and supply commenced during the second quarter of 1998 and December 1997, respectively. Gas allocation to Agra city is 0.3 MMSCMD and to Firozabad is 0.6 MMSCMD.

To date, no foundry unit in Agra has switched to natural gas, whereas 64 glass units in Firozabad have made the transition. This is mainly because the technology required for glass units in Firozabad to convert to gas is available but the same is not true for the foundry cluster at Agra. Also, investments required for converting to natural gas are relatively less in the glass units as compared to those in the foundry units. In August 1999, the Supreme Court ordered the closure of 53 foundries and 107 other factories in Agra that failed to comply with the earlier order of the court. However, the foundry industry filed a review petition through the UP State Government and obtained a reprieve on the court order's implementation. Thus, due to various reasons like delay in laying down the gas distribution network, lack of technology, huge investment requirements, resulting unemployment, the review petitions filed in the Supreme Court by various stakeholders, etc., actual implementation of the court's order has been dragging on for the last three years. Agra's Iron Foundry Association and various groups of glass units owners at Firozabad are building up their case against the Supreme Court order. Politicians have tended to side with the industry.

Transportation

Emission standards

Pollution due to petroleum products used in transportation is an ever increasing problem for Delhi and other metropolitan cities. Emissions causing concern are carbon monoxide, oxides of nitrogen, unburned hydrocarbons and particulates. Petrol-driven vehicles are a major source of carbon monoxide emissions contributing over 85%; diesel-driven vehicles contribute over 90% of emissions of oxides of nitrogen. Emissions of hydrocarbon and carbon monoxide from the large two- or three- wheeler population are very high.

Vehicular emission standards were first set in 1986 by the CPCB for both petrol- and diesel-driven vehicles. These were later revised in 1987 and 1989. However, these emission standards are with reference to the volume of air. They do not constitute mass emission norms, the first stage of which came out in 1991 for petrol vehicles and in 1992 for diesel vehicles. The next stage of mass emission norms, Euro I was initiated in 2000. The third stage, Euro II norms, will come into effect in 2005. The mass emission standards for diesel driven vehicles are given in Table 9.3. Mass emission standards for petrol driven vehicles and for diesel driven vehicles (gross weight<3.5 tonnes) are given in Annexure 9.5.

Table 9.3 Mass emission standards (g/kWh) for diesel driven vehicles

Gross vehicle weight>3.5 tonnes	1 April 1992	1 April 1996	1 April 2000 (Euro I)	Euro II	Euro III
Carbon monoxide	14.0	11.2	4.50	4.00	2.0
Hydrocarbon	3.5	2.4	1.10	1.10	0.6
Oxides of nitrogen	18.0	14.4	8.00	7.00	5.0
Particulate matter for > 85 kW	0	0	0.36	0.15	0.1
Particulate matter for < 85 kW	0	0	0.61	0.15	0.1

Source: AIAM (Association of Indian Automobile Manufacturers), 1999

Gas compared with other energy sources

Natural gas is primarily methane, a relatively simple molecule. It burns more completely than many fuels and hence produces fewer emissions of several types, particularly oxides of nitrogen. Emissions of carbon monoxide and pollutants that produce urban smog are significantly lower when CNG (compressed natural gas) is used as a fuel. Additionally, CNG vehicles do not produce emissions of 'smoke' particulate and cancer-causing toxins. The low emissions are mainly due to the efficient burning of the fuel. CNG as a fuel leads to complete combustion in vehicles. No additives are needed to reduce carbon deposits on sparkplugs or clean fuel injectors. Evaporative emissions, which contribute to urban smog, are virtually eliminated, as the CNG system is a totally closed one. When CNG and air in the right proportions are brought together, they mix thoroughly and rapidly, thereby improving the combustion efficiency, while the engine stays clean internally. CNG will not contaminate the ground water like liquid fuels.

CNG Vs Petrol

The emissions by a car using CNG as a fuel are compared with the emissions of a car running on petrol in Table 9.4. Use of CNG as a fuel reduces all the emissions, the most significant reduction being in carbon monoxide emissions.

Table 9.4 Mass emission for a car (ARAI, Automotive Research Association of India, test results)

Emission (gms/km)	CNG	Petrol
Carbon monoxide	0.94	16.50
Hydrocarbons	1.78	2.70
Oxides of Nitrogen	1.18	1.80
Carbon dioxide	132.54	150.00

Source: Auto India, August 1999

CNG Vs automotive diesel

A recent study by the Harvard Center for Risk Analysis (2000) points out that while natural gas reduces emissions of fine particles, it may generate more ultra-fine particles than diesel. Ultra-fine particles may have more severe adverse impacts on health as compared to fine particles. A CNG bus compared to an ordinary diesel (0.5% sulphur) bus reduces emissions of particulate by 86%, nitrogen oxide by 56%, hydrocarbons by 56% and carbon monoxide by 55% (Source: Auto India, August 1999). However, the comparison results are very different when ultra low sulphur diesel (ULSD) and CNG are compared. The level of carbon monoxide emitted by CNG is 0.66 gm, while for ULSD, it is 0.20 gm. The hydrocarbons emitted by CNG are nearly three times that of ULSD - 3.01 gm as compared to 0.14 gm. The ULSD, however, emits a larger amount of nitrogen oxides (11.90 gm) per km of travel as compared to the nitrogen oxide emissions (9.92 gm) per km by a CNG vehicle. Thus, ULSD emits less of every pollutant except nitrogen oxide.

There are various obstacles in converting existing diesel vehicles to CNG. High costs are involved in conversion and additional weights of CNG cylinders pose a problem. Proper infrastructure for re-filling and servicing needs to be built. CNG distribution infrastructure would require fresh investments while the diesel infrastructure already exists. All these factors need to be weighed against the environmental benefits that CNG offers, before taking any policy decision.

Fuel specification and engine technology should go hand in hand. While CNG is a good solution for improving air quality, there is large scope for finding out whether other cost-effective and environment-friendly options (for example, ultra low sulphur diesel) exist.

Case Study: Delhi

This case study illustrates the initiatives taken by the Delhi government and the Supreme Court to reduce vehicular pollution in Delhi. The move towards conversion of all public transport vehicles to CNG has faced severe technical and practical problems. The government should aim at developing stringent emission standards and ensuring strict compliance. It is best to leave the choice of fuel and technology to the vehicle manufacturers and fuel suppliers.

The number of vehicles in Delhi was 2.63 million in 1996 and is projected to grow to 4.6 million in 2004 and 6 million in 2011. The vehicular population is highly skewed towards two-wheelers, which account for about two-thirds of the total number of vehicles in Delhi. Vehicular pollution contributes to 67% of the total air pollution. Particulate matter pollution leads to 18,620 premature deaths annually in Delhi. A Public Interest Litigation was filed in the Supreme Court drawing attention to the deteriorating air quality in Delhi, mainly due to vehicular pollution. The Supreme Court appointed a statutory committee called the Bhure Lal Committee and based on its recommendations, issued various directives (dated July 28, 1998):

- Replacement of all pre 1990 autos and taxis with new vehicles on clean fuels (CNG) by March 31, 2000.
- No 8 year old buses to ply except on CNG or other clean fuels by April 1, 2000.
- Entire city bus fleet (DTC and private) to be steadily converted to single fuel mode on CNG by March 31, 2001.
- GAIL to expedite and expand from 9 to 80 CNG outlets by March 31, 2000.

I

Indraprastha Gas Limited (IGL) was incorporated in December 1998 for supplying gas to Delhi. CNG is distributed at 68 stations in Delhi and the present allocation of gas to the city is 0.48 MMSCMD. Currently, there are 150 CNG buses with the Delhi Transport Corporation (DTC), 12065 CNG auto-rickshaws and 839 CNG taxis. In an order dated March 26, 2001, the Supreme Court extended the CNG conversion deadline September 30, 2001 for commercial vehicle operators willing to convert their vehicles to CNG.

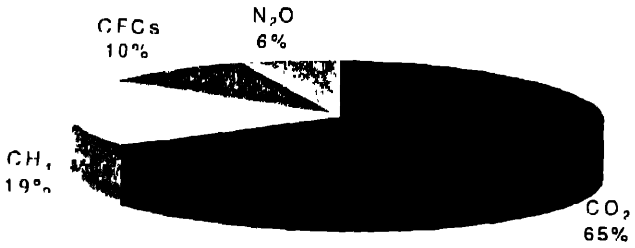
In the process of conversion to CNG, practical aspects like the feasibility of converting all the buses to CNG, availability of natural gas, proper infrastructure and the burden of increased costs of CNG buses on bus fares seem to have been ignored. Telco and Ashok Leyland are the only two companies manufacturing CNG buses and the only authorised company for conversion to the CNG mode is Nugas. Such constraining factors led to the inability to meet the March 31 deadline and it seems unlikely that the extended deadline of September 30, 2000 would be met. The public transport system and the environmental quality in Delhi can be improved by adopting a mix of various technical and strategic measures. Such measures would include compliance to stringent emission norms, rather than the imposition of a particular fuel, traffic management rules, modern vehicle technologies, and general awareness of the public towards the need for environmental protection.

Greenhouse gas emissions

Global climate change is an environmental problem caused by the increase in concentrations of greenhouse gases in the atmosphere. These gases include carbon dioxide (CO_2), chloroflurocarbons (CFCs), methane (CH_4) and nitrous oxide (N_2O).

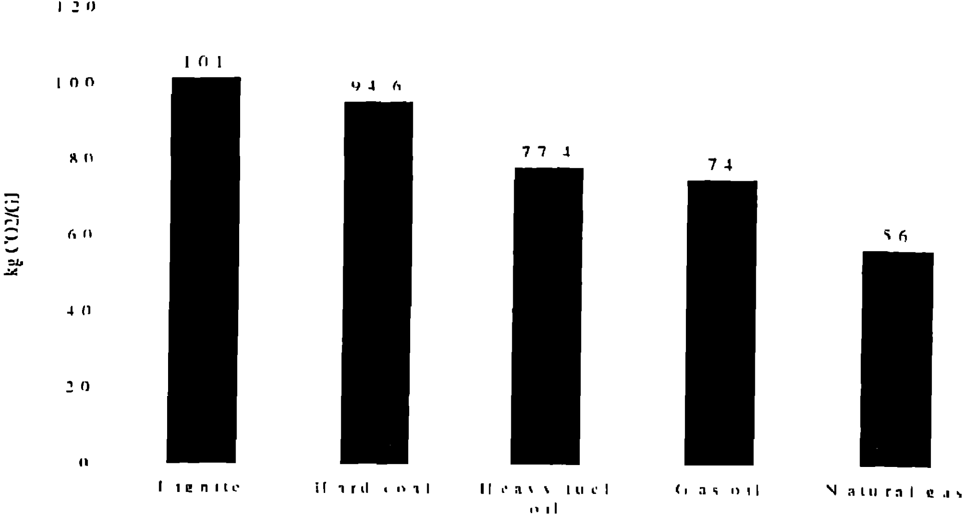
The emissions of carbon dioxide are responsible for about 65% of global warming in the world. The combustion of fossil fuels is responsible for 75-90% of all anthropogenic emissions of CO_2. On the basis of data presented by IPCC (Intergovernmental Panel on Climate Change), the relative contribution of anthropogenic emissions to the enhancement of greenhouse effect is estimated as shown in Figure 9.4.

Figure 9.4 Contribution to greenhouse effect



Natural gas generates less CO_2 for the same amount of energy supplied than either coal or oil. Due to its chemical composition, gas produces 40% less CO_2 than hard coal. Carbon dioxide emissions by different types of fuels can be seen in Figure 9.5. The share of natural gas in total primary energy consumption in India has been 8-9 % during the 1990s. Increasing use of natural gas will reduce CO_2 emissions into the atmosphere.

Figure 9.5 CO_2 emissions by combustion of fuels



The relationship between economic activity, energy use and the environment is evident. Pollution is bound to occur during economic development. There are several ways of controlling pollution like use of cleaner fuels, preventing pollution at source, optimal utilization of resources, recycling, reuse and recovery of the valuable resources and ultimately treatment and disposal of inevitable wastes. Natural gas is a superior energy form when all the environmental impacts are considered.

Annexure 9.1 Air quality standards:

Guidelines/standards for sulphur dioxide

Guidelines set by	Description	Criteria based on	Concentration (µg/m^3)
European Council	Limit Value	98percentile of hourly means	128
World Health Organisation	Health Guidelines	10 minutes means	500
		1-hour mean	350
		Daily mean	125
India	Industrial Area	Annual average	80
		24 hours	120
	Residential, rural and other areas	Annual average	60
		24 hours	80
	Sensitive Areas	Annual average	15
		24 hours	30

Guidelines/standards for nitrogen dioxide

Guidelines set by	Description	Criteria based on	Concentration (µg/m^3)
European Council	*Limit Value*	*98percentile of hourly means*	200
World Health Organisation	Guidelines	98percentile of hourly means	135
	Guidelines	50percentile of hourly means	50
	Health Guidelines	1 hourly means	400
	Health Guidelines	Daily mean	150
India*	Industrial Area	Annual average	80
		24 hours	120
	Residential, rural and other areas	Annual average	60
		24 hours	80
	Sensitive Areas	Annual average	15
		24 hours	30

*Oxides of nitrogen (NO and NO_2)

Guidelines/standards for carbon monoxide

Guidelines set by	Description	Criteria based on	Concentration (µg/m^3)
European Council	Health Guidelines	15 minute mean	100
World Health Organisation	Health Guidelines	30 minute mean	60
	Health Guidelines	1 hour mean	30
	Health Guidelines	8 hour mean	10
India	Industrial Area	8 hours	5
		1 hour	10
	Residential areas	8 hours	2
		1 hour	4
	Sensitive Areas	8 hours	1
		1 hour	2

Annexure 9.2 Environmental standards for thermal power plants

Parameters	Indian Emission Standards		
	Capacity	Fuels	Standards
Particulate matter	Less than 200/210 MW	Coal	350 mg/Nm^3
	200/210 MW and above	Coal	150 mg/Nm^3
Sulphur di-oxide (SO_2)	Less than 200 MW	Coal	$H=14 (Q)^{0.3}$ where H=stack height in metres Q=emission rate of SO_2 in kg/hr
	200 MW and less than 500 MW	Coal	220 m stack height
	500 MW and above	Coal	275 m stack height
Nitrogen oxides (NO_X)	All existing units	Natural gas /naphtha	150 ppm at 15% excess oxygen
	New units (effective from January 1, 1998)		
	400 MW and above	Natural gas	50 ppm (parts per million)
		Naphtha	100 ppm
	100-400 MW	Natural gas	75 ppm
		Naphtha	100 ppm
	Less than 100 MW	Natural gas	100 ppm

Source: MoEF

Annexure 9.3a Effluent standards for thermal power plants (CPCB)

Source	Parameter	Max limiting concentration Miligram/litre (except for pH and temperature)
Condenser cooking water (once through cooling system)	PH	6.5-8.5
	Temperature	Not more than 5 °C higher than the intake water temperature
	Free available chlorine	0.5
Boiler blowdowns	Suspended solids	100
	Oil and grease	20
	Copper (total)	1.0
	Iron (total)	1.0
Cooling tower blowdowns	Free available chlorine	0.5
	Zinc	1.0
	Chromium (total)	0.2
	Phosphate	5.0
	Other corrosion inhibiting material	Limit established on case by case basis
Ash pond effluent	PH	6.5-8 5
	Suspended solids	100
	Oil and grease	20

b) World Bank proposed effluent levels for thermal power plants

Parameters	Maximum level Milligram/litre (except for pH and temperature)
pH	6-9
Total Suspended Solids	50
Oil and grease	10
Total Residual Chlorine	0.2
Chromium (total)	0.5
Copper	0.5
Iron	1.0
Zinc	1.0
Temperature increase	Less than or equal to 3 °C (100 m from point of discharge)

Annexure 9.4 Emission standards for selected industries

Integrated iron and steel plants - Emissions	
Pollutant and Sources	Emission limit (mg/m^3)
Particulate matter	
Sintering plant	150
Coke oven	50
Steel making	
During normal operation	150
During oxygen lancing	400
Carbon monoxide	
Coke oven (kg/tonne of coke produced)	3

Cement plants - Particulate matter emissions (mg/m^3)		
Capacity	Protected areas	Other areas
200 TPD (tonnes per day)	250	400
Greater than 200 TPD	150	250

Fertilizer plants		
Product	Pollutant	Emission limit (mg/m^3)
Urea - Prilling tower	Particulates	50
Phosphatic fertilizer		
Acidification of rock phosphate	Fluorides	25
Granulation, mixing and grinding of rock phosphate	Particulates	150

Aluminium industry - Particulate matter emissions (mg/m^3)	
Process	Emission limit (mg/m^3)
Calcination	250
Smelting	150

Source: CPCB 1998

Annexure 9.5 Emission standards for vehicles

a) Diesel-driven vehicles

Mass emission standards for diesel driven vehicles

Gross vehicle weight < 3.5 tonnes	1 April 1992 (g/kWh)	1 April 1996 (g/km)	1 April 2000 (g/km)
Carbon monoxide	14.0	5.0 - 9.0	2.72 - 6.90
Hydrocarbon	3.5	--	--
Oxides of nitrogen	18.0	2.0 - 4.0	0.97 - 1.70
Particulate matter for	0.0	--	0.14 - 0.25

b) Petrol-driven vehicles

Four-wheelers - passenger vehicle

	1 April 1991	1 April 1996		1 April 2000	1 April 2005
		Without catalytic converter	With catalytic converter	Euro I Norm	Euro I Norm
Carbon monoxide	14.3 - 27.1	8.68 - 12.40	4.34 - 6.20	2.72	2.2
Hydrocarbon	2.0 - 2.9	--	--	--	--
Hydrocarbon and oxides of nitrogen	--	3.00 - 4.36	1.50 - 2.18	0.97	0.5

Two-wheelers

	1 April 1991	1 April 1996 Indian driving cycle with warm start	1 April 1998 Indian driving cycle with cold start	1 April 2000 Indian driving cycle with cold start
Carbon monoxide	12 - 30	4.5	4.5	2
Hydrocarbon	8 - 12	--	--	--
Hydrocarbon and oxides of nitrogen	--	3.6	3.6	2

Three-wheelers

	1 April 1991	1 April 1996 Indian driving cycle with warm start	1 April 1998 Indian driving cycle with cold start	1 April 2000 Indian driving cycle with cold start
Carbon monoxide	12 - 30	6.75	6.75	4
Hydrocarbon	8 - 12	--	--	--
Hydrocarbon and oxides of nitrogen	--	5.40	5.40	2

10 Investment profile

Import requirements

India's gas requirements are projected to reach 150 MMSCMD by 2015. Domestic gas production, including CBM, is expected to be about 48 MMSCMD only, unless there are large offshore discoveries particularly in the KG basin. Imports have been estimated at 102 MMSCMD or 27 MMTPA. For purposes of determining the investments to be made over a 15 years period, it is assumed in this chapter that matching terminal capacity of 30 MMTPA will be constructed and operational by 2015, even though the collective capacity of the terminals being planned currently is 38.5 MMTPA. Should any piped gas proposal materialise, the cost of the pipeline and other infrastructural costs will need to be included with a corresponding scaling down of liquefaction, shipping and regasification costs for LNG.

Investment projections

LNG is produced from natural gas through liquefaction (cooling the gas to minus 160°c thereby reducing it to almost 1/625th its original volume) and transported over long distances in special purpose tankers. At the receiving terminal, LNG is stored, regasified and then transported through pipelines as natural gas. The sequential steps are:

- Gas production (upstream)
- Liquefaction
- LNG shipping
- Receiving and regasification terminal
- Transmission and distribution

These steps are typically referred to as a "LNG Chain". All elements of the chain are to be in place to make the entire chain operational. Typical cost elements for a 2.5 MMTPA LNG chain were provided in the Natural Gas Master Plan study. Since then (1998) there have been a significant lowering of cost estimates. The two sets of estimates are provided in Table 10.1

Table 10.1 Cost components of a 2.5 MMTPA LNG chain (Million $)

Activity	Typical cost (Master Plan)	Typical cost (current)
Upstream	400	200
Liquefaction	750	630
Shipping	400	180
Regasification	400	270
Total	**1950**	**1280**

Based on the current unit costs, the total investment in the LNG network over the period 2001 to 2015 is estimated in Table 10.2

Table 10.2 Investments in a 30 MMTPA LNG network

	$ million	Rs billion	%age	Remarks
Upstream	2,400	110	12	Outside India
Liquefaction	7,560	355	38	Outside India
Shipping	2,200	103	11	Outside India with some Indian equity participation
Regasification	3,240	152	16	Within India
Transmission*	4,400	202	22	Within India
Total	19,800	922	100	

* see below under 'Transmission and distribution'

Upstream and Liquefaction

Some of the capacity required already exists by way of facilities that are operational but not working to full capacity. Also, some capacity is under construction to meet the requirement to start supplies to India by 2004/5.

Shipping

The Natural Gas Master Plan "typical" shipping costs at $400 million per 2.5 MMTPA is applicable to long distance tanker voyages e.g. Middle East-Japan and would be lower for India. Based on the cost of $158 million each for the two tankers under construction for Petronet LNG and a projected requirement of around 14 tankers to service India's import requirement of 30 MMTPA LNG, the current shipping cost has been determined in Table 10.2.

Regasification

Typically, regasification projects have a debt-equity ratio of 70:30, which would indicate a total debt component of about $ 2270 million for the proposed investments.

Promoters typically employ project financing with limited recourse, i.e., limited contractual obligations of project promoters by creating a Special Project Vehicle

(SPV) which contracts with both LNG suppliers and downstream customers. Financiers try to ensure that the SPV contracts mitigate project risks. Typically, concerns of lenders could be categorised as follows (Cook, 2001),

Construction

Timely construction, capabilities of contractor, force majeure conditions, etc.

Operations

Project maintenance, capabilities of O&M contractor, operational efficiency, capacity utilisation, labour problems, etc.

Equipment

Suitability of chosen equipment for the situation, timely delivery, availability of spares/replacements, technology risks, stability of the manufacturer, etc.

Economic

Unexpected costs, problems with currency conversion, repatriation of funds, tax changes, policy changes, reliability of sinking funds and government agreements, etc.

Throughput

Sufficiency of throughput at rates to assure debt service and project health, credit rating of customers, etc.

Political

Political or cross border risks such as private ownership, taxes, emissions, currency, contract repudiation, expropriation, nationalization, insurrection, etc.

Mitigating these risks usually involves proving the reliability of EPC contracts, O&M contracts, sales agreements, sovereign guarantees, resource studies, equipment performance data and setting sufficient sinking funds to cover unexpected problems. Sponsors also consider risk mitigation by arrangement of debt facilities from multilateral institutions and international export credit agencies. Issues such as excess capacity of the terminal, sufficiency of throughput at rates to assure project health and contract repudiation have been highlighted in the current stand-off between DPC and the MSEB. The contract was perhaps fatally flawed from the beginning and several lessons need to be quickly learned by all stakeholders to ensure a smoother ride for the other projects.

Agencies like the International Finance Corporation (IFC), a subsidiary of the World Bank, provide long term market-priced capital both as equity and loans. Generally, IFC finances only a portion of the project cost, but mobilises funds from other sources. Long-term loans, which IFC writes on its own account are referred to as A loans. Syndicated or B Loans are easily mobilised as IFC's participation in a project is often seen as a seal of approval by other lenders.

An export credit arises whenever a foreign buyer of exported goods or services is allowed to defer payment. Export credits are generally classified as short-term (repayment terms of usually under two years), medium term (usually two to five years) and long-term (over five years). Export credits may take the form of supplier credits or buyer credits. Supplier credits are extended by an exporter directly to an overseas buyer. Buyer credits are extended by an exporter's bank or other financial institution as loans to the buyer. Supplier/buyer credits are arranged by export credit agencies (ECAs). Promoters generally tend to maximise ECA funding for foreign currency.

Transmission & distribution

Investments in transmission/distribution networks, would be customer specific, depending on the location of customers, the contracted volumes, etc. The long term plans for gas transmission pipelines in Chapter 8 envisage a national grid of 8000 km length; an addition of 5700 km to the existing HBJ pipeline of 2300 km. Capacity costs for transmission pipelines including compressor stations are estimated at $35,000 per inch dia per km. An average pipeline diameter of 22" has been assumed. Investments required for local gas distribution networks have not been evaluated.

GAIL has indicated investment plans of about Rs 100 billion over the next few years on various schemes (GAIL, 1999). These include about Rs 30 billion ($650 million) for increasing the capacity of the HBJ pipeline system to 60 MMSCMD and Rs 6 billion ($130 million) on setting up new pipelines in the Krishna-Godavari and Cauvery basins. The Gujarat State Petroleum Corporation has set up a separate company, Gujarat State Petronet Ltd (GSPL) to develop a distribution network spanning some 1500 km at a cost of Rs 24 billion ($520 million). More specific plans are likely to be announced once the proposed LNG terminals reach financial closure.

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